expansion, EPSA also advocates that the RTO should be delegated sufficient authority to direct transmission owners or others to excise their eminent domain authority, as necessary, to implement transmission system expansion plans independent of the source of funds or the beneficiary of the project. Under current law, this authority must come from the states. Thus, EPSA also advocates the passage of Federal legislation that vests the Commission with primary jurisdiction over major transmission planning and siting decisions, perhaps subject to a requirement that the Commission consult with a regional siting authority or a consortium of affected state siting boards.

Central Maine disagrees and recommends that the Commission should reject EPSA's comments. Central Maine notes that, if a state government intends that an RTO have the power of eminent domain, the state legislature will grant it. Central Maine argues that RTOs should not be granted the power to do something indirectly that they may not do directly. Consequently, it believes that EPSA must pursue its proposal through the enactment of state legislation.

Whether Three Years Is an Appropriate Amount of Time for Implementation of This Function. Several commenters support the Commission's proposal to allow up to three years to implement the planning and expansion function.[589] Some commenters, however, believe that three years is too short.[590] South Carolina Authority suggests a five-year period. Florida Commission believes that it is premature to set any time limit for implementation of the planning and expansion function.

On the other hand, several commenters believe that three years is too long a period.[591] Most of these commenters believe that the planning and expansion is such an important function that its implementation should not be delayed at all. NYC suggests that implementation should not be delayed more than a year. SRP argues that the uncertainty that currently exists about who ultimately will be responsible for building and paying for new transmission facilities is causing delays in upgrades. According to SRP, requiring the RTO to perform this function upon commercial operation will eliminate this uncertainty.

Industrial Customers also argues that any delay should not be used as an excuse to stall the construction of any facility for which the need has been established. SRP suggests that, if a delay in implementation is permitted, the RTO should be required to identify the entity responsible for financing and building transmission expansion prior to the RTO assuming such responsibility.

Commission Conclusion. We reaffirm the NOPR proposal that the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities. In carrying out this overall responsibility, the Commission has concluded that the NOPR's three separate requirements for RTO planning and expansion must also be satisfied or, in the alternative, the RTO must demonstrate that an alternative proposal is consistent with or superior to these three requirements. Specifically, an RTO must satisfy the requirement to: (1) Encourage market-motivated operating and investment actions for preventing and relieving congestion; (2) accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary; and (3) file a plan with the Commission with specified milestones that will ensure that it meets the overall planning and expansion requirement no later than three years after initial operation, if the RTO is unable to satisfy this requirement when it commences operation.

As noted above, the RTO should have ultimate responsibility for both transmission planning and expansion within its region. The rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability. We also recognize that the RTO's implementation of this general standard requires addressing many specific design questions, including who decides which projects should be built and how the costs and benefits of the project should be allocated.[592] As with other requirements of the Final Rule, we propose to give RTOs considerable flexibility in designing a planning and expansion process that works best for its region. It is both inevitable and desirable that the specific features of this process "should take account of and accommodate existing institutions and physical characteristics of the region."[593] We emphasize that, as the transmission provider in the region, the RTO is required to provide service under a tariff that is consistent with or superior to the Commission's *pro forma* tariff, and that tariff obligates the transmission provider to expand and modify its system to provide the services requested under the *pro forma* tariff.[594] Because an RTO may not own all of the facilities it operates, we clarify that nothing in this Rule relieves any public utility of its existing obligation under the *pro forma* transmission tariff to expand or upgrade its transmission system upon request. Accordingly, we shall evaluate each RTO proposal to ensure that the RTO can direct or arrange for the construction of expansion projects that are needed to ensure reliable transmission services.[595] However, the Commission reiterates, as discussed below, its strong preference for market-motivated operating and investment actions.

We further note that the pricing mechanisms and actions used by the RTO as part of its transmission planning and expansion program should be compatible with the pricing signals for shorter-term solutions to transmission constraints (*i.e.,* congestion management) so that market participants can choose the least-cost response. Otherwise, their choices may reflect less efficient outcomes for the marketplace. For example, if the price of expansion overstates its cost (or the price of congestion management understates actual congestion cost), market participants likely will continue congestion management solutions to a transmission constraint when

[589] *See, e.g.,* Tri State, SoCal Edison and PNM.

[590] *See, e.g.,* NECPUC, Duke and South Carolina Authority.

[591] *See, e.g.,* Champion, NYC, Turlock, SRP, TDU Systems and Industrial Customers.

[592] FERC Stats. and Regs. ¶ 32,541 at 33,751–52.

[593] *Id.* at 33,752.

[594] *See, e.g.,* Section 15.4 of the *pro forma* tariff which requires the transmission provider to use due diligence to expand or modify its transmission system to provide requested services. Also, Section 28.2 of the *pro forma* tariff requires the transmission provider to plan, construct, operate and maintain its transmission system in order to provide network service, and to endeavor to construct and place into service sufficient transmission capacity to deliver network resources to network customers on a basis comparable to its own use of the transmission system.

[595] We note that existing ISOs have addressed similar issues successfully. For example, the PJM ISO is responsible for expansion planning, but the transmission owners remain obligated to undertake upgrades necessitated by the plan, 81 FERC ¶ 61,257 at 62,275 (1997).

expanding the system to relieve congestion is more efficient.

Market-Motivated Actions. Planning new generation or new transmission requires a coordinated approach to ensure reliability and efficient congestion management. However, this does not necessarily imply that all transmission expansions must be centrally planned by the RTO. Where feasible, an RTO should encourage market approaches to relieving congestion. A market approach will require providing all transmission customers with access to well-defined transmission rights and efficient price signals that show the consequences of their transmission usage decision. If the RTO's market approach is successful, the decisions of where, when and how to relieve congestion will be driven by economic considerations.

Most commenters agree with the NOPR proposal that RTOs should rely upon market signals and market solutions in assessing all feasible options (*e.g.,* construction of new generation, redispatch of existing generation, as well as expansion of the transmission grid) to assure that the least costly option is pursued. If an RTO can facilitate market-motivated decisions, several commenters point out that its planning role may largely be limited to extreme circumstances where continuing congestion in an area threatens reliability. However, we also recognize that different market approaches to relieving congestion are still in the early stages of development. Similarly, while market approaches to expansion are the subject of much discussion, they are also in the early stages of development.[596] It is not the intent of the Commission either to mandate a market approach to the exclusion of an executive decision by the RTO or to mandate any particular market approach.

Nevertheless, if any market-driven approach is to be successful, there must be accurate price signals that reflect the costs of congestion and expansion costs. As we stated in the NOPR, accurate price signals are the link between current usage and future expansion. Therefore, as discussed in more detail in Section III.E.2 Congestion Management, every RTO must establish a system of congestion management that establishes clear rights to transmission facilities and provides market participants with price signals that reflect congestion and expansion costs. In implementing its planning and expansion responsibility, an RTO must ensure that its decisions are not unduly discriminatory and produce efficient outcomes.

The Commission reaffirms its statement in the NOPR that independent governance of the RTO is a necessary condition for nondiscriminatory and efficient planning and expansion. While accurate price signals can signal the need for expansion, such expansion may not be achieved if an RTO operates under a faulty governance system (*e.g.,* a governance system that allows market participants to block expansions that will harm their commercial interests).

Multi-State Agreements and RTGs. The final rule fully recognizes the statutory authority of the states to regulate siting of transmission facilities. Currently, state and local governments and regulatory agencies have exclusive authority over the siting process. Therefore, an RTO's planning and expansion process must be designed to be consistent with these state and local responsibilities.

RTOs must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The Commission encourages the development of multi-state agreements or compacts to review and approve new transmission facilities. This would expedite transmission construction and eliminate duplicative (and possibly conflicting) reviews by multiple states. To facilitate any voluntary actions taken by our state colleagues, we will require that the RTO planning and coordination system must be able to accommodate the possible emergence of new regional regulatory systems.

Existing RTGs have clear and prominent roles in transmission expansion decisions in which planning for transmission improvements are coordinated through collaborative processes. To avoid duplicative efforts, the RTO process must build on existing RTG planning processes. Over time, since the RTO will have ultimate responsibility for planning the entire transmission system within its region, we expect that the functions of an RTG will be assumed by an RTO to avoid unnecessary duplication of effort.

Three-Year Implementation. If the RTO is unable to satisfy the planning and expansion function when it commences operation, it must file a plan with the Commission with specified milestones that will ensure that it meets this requirement no later than three years after initial operation. Recognizing that the planning and expansion function may require coordination among multiple parties and regulatory jurisdictions, we do not require this function to be in place at the initial operation of the RTO. We continue to believe that three years is a reasonable deadline for creating an operational planning and expansion system. Therefore, we will not extend this deadline or the requirement to file a plan with the Commission with an implementation timetable. This time period could be affected by the RTO's scope, the number of states and market participants, and implementation costs; however, the urgent needs of the electricity markets make us disinclined to extend these deadlines.

However, the delay should not stall the construction of new or enhanced facilities for which needs have been established, unless the RTO makes a positive decision that the facility is not in the best interests of the region. Delaying transmission expansion could result in significant market inefficiencies as well as unacceptable risks to reliability given the long regulatory and construction lead times required to build new facilities.

8. Interregional Coordination (Function 8)

In Order No. 888, the Commission identified eleven principles it would use to assess Independent System Operator (ISO) proposals submitted to the Commission.[597] One of these principles required that the ISO develop mechanisms to coordinate with neighboring control areas to ensure reliability and the provision of transmission services that cross system boundaries. The RTO NOPR encouraged transmission entities to consider ways to reduce impediments to transactions among themselves,[598] but a coordination requirement was not included explicitly in the RTO NOPR. Several commenters pointed out that there was no explicit coordination requirement proposed in the RTO NOPR and recommended including a function for RTOs similar to the coordination principle in Order No. 888.

[596] For example, TDU Systems and other commenters suggest that, by promoting competition for new construction, the RTO can minimize construction cost and also reduce its own risk profile. For example, an ISO in Victoria, Australia (VPX), which operates, but does not own transmission assets, uses competitive bidding for new transmission facilities. At the Regional ISO Conference in Richmond, Virginia on June 8, 1998, Raymond Coxe described how VPX's strategy resulted in a number of bidders competing for the right to build, own and operate new facilities. He concluded that the ''result of this competition was a lower price to the consumers of Victoria than would have resulted from regulated transmission service by the largest incumbent provider.'' Transcript at 86, Docket PL98–5–006.

[597] Order No. 888, FERC Stats. and Regs. ¶ 31,036 at 31,730–32.

[598] FERC Stats. and Regs. ¶ 32,541 at 33,758.

Comments. Several commenters identify coordination with other regions as a necessary element that should be added more explicitly to the RTO functions.[599] These commenters express this need as either required to ensure reliability or necessary for bulk power markets to operate over sufficiently large areas. For example, NERC states that the need for such coordination effort has increased as the management of short-term reliability of the interconnected bulk power system and the operation of increasingly competitive bulk power markets have become inseparable. Accordingly, NERC recommends that an additional function be added to the final rule that requires RTOs to integrate their market interface practices and reliability practices. It identifies OASIS standards, information sharing with neighboring RTOs, ancillary services requirements, parallel path flows, transmission loading relief, and interregional congestion management, as practices and standards that need to be integrated.

Duquesne states that efficiencies can be realized from coordinating and developing a seamless marketplace. It recommends that the Commission require RTOs to coordinate and plan for seamless and uniform transmission rules, scheduling systems and procedures, and reliability standards. In addition, Oneok suggests that the Commission encourage neighboring RTOs to form reliability compacts under which loop flow and other issues involving interregional reliability impacts can be resolved.[600] Also, Wyoming Commission believes that the Commission should be flexible with respect to inter-RTO interaction and that it may be appropriate to address these issues later rather than in initial RTO filings.

Commission Conclusion. Coordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets. In the NOPR, we discussed several region-to-region coordination activities in connection with the parallel path, congestion management, and expansion planning functions. However, the comments persuade us to add a more general interregional coordination requirement as one of the minimum RTO functions.

We will require an RTO to develop mechanisms to coordinate its activities with other regions whether or not an RTO yet exists in these other regions.[601] If it is not possible to set forth the coordination mechanisms at the time an RTO application is filed, the RTO applicant must propose reporting requirements, including a schedule, for itself to provide follow-up details as to how it is meeting the coordination requirements of this function. We expect the RTO to work closely with other regions to address interregional problems and problems at the ''seams'' between the RTOs. Therefore, as recommended by NERC and others, we will add the following regulatory text to our RTO Final Rule functions:

(8) *Interregional Coordination:* The Regional Transmission Organization must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

An RTO proposal must explain how the RTO will ensure the integration of reliability and market interface practices. An RTO may ensure the integration of these practices either by developing integration practices itself or by cooperating in the development of integrated practices with an independent entity that covers all regions or, for reliability practices, covers an entire interconnection. The term, interconnection,[602] refers here to any one of three large U.S. transmission systems. The Eastern Interconnection covers most of the area east of the Rocky Mountains in the United States and Canada. The Western Interconnection covers an area that is mostly west of the Rocky Mountains in the United States and Canada, as well as a small portion of Mexico. The Electric Reliability Council of Texas (ERCOT) Interconnection covers much of Texas.

This provision does not mean that all RTOs necessarily must have a uniform practice, but that RTO reliability and market interface practices must be compatible with each other, especially at the ''seams.'' RTOs must coordinate their practices with neighboring regions to ensure that market activity is not limited because of different regional practices.

We understand, as NERC pointed out in its comments, that the reliability and market interface practices are becoming highly interrelated. The reliability practices affect how markets interface with each other, and the market interface practices affect reliability. For example, TLR and congestion management are both used to unload an overloaded transmission interface, and these two practices must work together. We consider congestion management and TLR are best used as sequential steps to unload a line, with congestion management used first to unload a line in a market-oriented manner, and TLR used to unload a line in a fair manner when either congestion management is unavailable or an emergency condition requires immediate action. We therefore list below TLR as a reliability practice and congestion management as a market interface practice, understanding that these and other practices listed affect both reliability and markets.

The integration of reliability practices involves procedures for coordination of reliability practices and sharing of reliability data among regions in an interconnection, including procedures that address parallel path flows, ancillary service standards, transmission loading relief procedures, among other reliability-related coordination requirements in this Final Rule.

The integration of market interface practices involves developing some level of standardization of inter-regional market standards and practices, including the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures, as well as other market coordination requirements covered elsewhere in this Final Rule.

F. Open Architecture

In the NOPR, the Commission stated its commitment to a policy of ''open architecture'' and proposed to require that RTOs be designed so that they can evolve over time. The Commission noted that there should be no provision in any RTO proposal that precludes the RTO and its members from improving their organization to meet market needs.[603] The Commission sought comments regarding the open architecture policy in general and the flexibility needs of RTOs in particular.

Comments. Virtually all commenters support the NOPR's open architecture concept and recommend that an RTO have the ability to evolve over time as

[599] Many parties supported this requirement including NERC, Justice Department, NARUC, NASUCA, Oneok, PJM, Duquesne and Industrial Consumers.

[600] ISO–NE, NY ISO and PJM recently signed a memorandum of understanding concerning interregional coordination activities.

[601] This is similar to the existing ISO Principle #10 in Order No. 888 for single control area ISOs: ''An ISO should develop mechanisms to coordinate with neighboring control areas.''

[602] ''Interconnection'' is a term used by the North American Electric Reliability Council and others to refer to an interconnected alternating current transmission system. Engineering considerations require all generators connected to any one interconnection to operate in a coordinated manner, that is, synchronously.

[603] FERC Stats. and Regs. ¶ 32,541 at 33,753.

it gains operating experience.[604] They endorse the principle of flexibility to accommodate the changing needs of the market.[605] WEPCO notes that open architecture should permit flexibility and urges the Commission not to require an RTO to be the only control area operator in the region.[606] Ontario Power states that the open architecture policy should enable RTOs to accommodate Canadian entities in the future. Oglethorpe observes that open architecture policy would allow RTOs to utilize existing infrastructure and avoid high transition costs.

However, Central Maine and Southern Company argue that the flexibility implied by open architecture should not be used carte blanche. For example, there should be limits to an RTO's evolution process because transmission owners have some fundamental rights, such as: (1) The right to terminate their participation in the RTO; (2) the right to switch to another RTO; (3) the right to merge RTOs; (4) the right to recover their costs and a return on investment; and (5) the right to protect their assets and employees from damages and injuries.

LG&E states that the flexibility inherent in the open architecture concept should be applied fairly to all market participants, including those transmission owners that have already committed to existing or proposed ISOs. For example, a member of an existing ISO should be allowed to move to another RTO.

Industrial Consumers perceives a potential downside to the open architecture policy in that it may give existing IOUs a license to continue their opportunistic behavior rather than facilitating true market transformation. Therefore, Industrial Consumers argues that it supports the notion of flexibility inherent in the open architecture policy only in the absence of market power. Illinois Commission argues that the pace of evolutionary improvement of RTOs should not remain in the hands of vertically integrated utilities because their interest in structural change may not be consistent with the public interest.

Cinergy, EPSA and Georgia Transmission state that the flexibility implied by open architecture should not be used to support deviations from minimum characteristics and functions. However, CP&L believes that the proposed minimum characteristics and functions are too stringent and do not allow for much flexibility that a changing market needs.[607] Georgia Transmission supports the Commission's commitment to providing regulatory flexibility to allow RTOs to evolve.

Many commenters state that the open architecture concept is so broad that it will prevent stakeholders from developing meaningful RTO proposals. To bring some certainty to the negotiating parties to an RTO proposal, CP&L recommends that the Commission find that some necessary and reasonable limitations on modifications to RTOs are permissible, and these can be overridden only by unanimous consent or a supermajority vote.[608] MidAmerican states that the Commission should accept RTO proposals that contain stated limitations, such as a transmission owner's right to withdraw from an RTO. MidAmerican argues that such limitations are consistent with the Commission's open architecture policy and would prevent transmission owners from being discouraged to join RTOs. To promote certainty, Entergy notes that the Commission should establish a general policy of grandfathering previously approved RTOs and not altering their requirements except in extraordinary circumstances.[609]

Southern Company is concerned that RTOs could evolve in ways that are undesirable to the participants that initiated its formation. Therefore, it argues that the parties should have some assurance that certain key provisions of an RTO would not change in the name of RTO evolution. For example, functions, boundaries, transmission rate design, and allocation of transmission revenues should not be amended by the RTO except by vote of the transmission owners, at least for the duration of a specified transition period. Southern Company contends that the transmission owners will then know what they are ''getting into'' when they join an RTO.

Many commenters recommend that the Commission should not mandate the ultimate organizational form of the RTO given the electric industry's current state of structural flux and the uncertainty of the future. These commenters argue that the Commission's open architecture policy should encourage market participants to develop transmission institutions that are effective in meeting the needs of the marketplace. FirstEnergy and NU state that there is a range of organizational and functional forms—power pool (tight and loose): gridco, transco, marketco—which can accomplish the Commission's goal of improving the efficiency of the transmission grid, and only time and market forces should determine which form is best suited for a specific region of the country. Southern Company believes that there should be no requirement that would prohibit an RTO with no transmission ownership to transform into one that owns transmission (*i.e.*, change from an ISO to a transco).

PJM urges the Commission to clarify that RTOs can propose improvements to the RTO independently of its members to meet changing market needs. PSE&G is opposed to giving such authority to RTOs because it believes that the market participants rather than RTOs should drive changes in the structure and operation of electric markets.[610] Cal ISO recommends that the Commission's open architecture policy should support the creation of a structure that facilitates the addition of new participants, both within and outside of the existing RTO boundaries. Illinois Commission urges the Commission to modify the proposed paragraph 35.34(k) of proposed regulations to include an affirmative expectation that RTOs *will* change to meet new competitive market needs and to improve over time.

Commission Conclusion. As proposed in the NOPR, we adopt the principle of open architecture in order that the RTO and its members have the flexibility to improve their organizations in the future in terms of structure, geographic scope, market support and operations to meet market needs. We will require that the RTO design have the ability to evolve over time. In addition, we will provide flexibility to allow RTOs to propose changes to their enabling agreements to meet changing market, organization and policy needs.

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[604] *See, e.g.,* APX, Arizona Commission, Cal ISO, Central Maine, Consumers Energy, CP&L, Conectiv, Desert STAR, DOE, Duke, Entergy, EPSA, FirstEnergy, Florida Commission, Georgia Transmission, Illinois Commission, Industrial Consumers, LG&E, NERC, NPCC, NSP, NU, NY ISO, Oglethorpe, PJM, Seattle, Southern Company, SMUD, SRP, TDU Systems, TEP, Tri-State and WEPCO.

[605] NSP states that the configuration of electric markets will be much different five or ten years from now.

[606] WEPCO notes that costs savings associated with creating large, efficient electricity markets will dwarf the savings attained by reducing the number of operators through control area consolidation.

[607] CP&L and Southern Company state that the Commission should establish basic RTO guidelines through a policy statement rather than by a rule. They contend that the rules under the NOPR are too prescriptive, and will stifle the development of new RTOs.

[608] CP&L notes that participants in Midwest ISO identified certain conditions that could be altered only by the transmission owners, including revenue distribution, pricing methodology and withdrawal rights.

[609] Entergy at 42.

[610] PSE&G Reply Comments at 6–7.

Open architecture will permit RTOs to evolve in several ways, as long as proposed changes continue to satisfy RTO minimum characteristics and functions. As a first example, open architecture will allow basic changes in the organizational form of the RTO to reflect changes in facility ownership and revised corporate strategies. As noted by Southern Company, an RTO that initially does not own any transmission facilities might acquire ownership of some or all of those facilities. With an open architecture design, the RTO's enabling agreements should anticipate and facilitate changes of this nature.

Second, open architecture design accommodates change in the geographical scope of RTOs. Electric markets are evolving quickly and future market trading patterns cannot be foreseen at the time of RTO organization. An open architecture design will enable an RTO to grow geographically and possibly merge with another RTO as changes in markets suggest a realignment of organizations to meet evolving market needs.

Third, market support is another area that benefits from open architecture design. For example, an RTO may not initially operate a PX to support a regional spot market, but later determine that the establishment of a PX would provide additional benefit in its region. With open architecture, the RTO can propose to add a PX function (or a PX monitoring function) to its design. Open architecture design ensures that such future developments that are beneficial to the marketplace are not foreclosed.

Fourth, open architecture design accommodates changing operational needs. Most commenters agree that, as RTOs gain operating experience, some changes will become necessary. Cal ISO acknowledges that it had to make significant changes to its tariff and operational practices as it gained operating experience, and it believes further modifications are likely to be identified as additional experience is gained regarding evolving competitive markets.

Finally, as noted in the NOPR, technological change make changes in RTO design inevitable and desirable. Accommodating that change will require flexibility and adaptability in the RTO organization; open architecture will permit design modification to keep pace with technology.

Some commenters argue that the flexibility implied by open architecture design should not be interpreted to mean unfettered ability on the part of the RTO to modify its structure or processes. We agree. Although under our open architecture policy the RTO will have the ability to propose whatever changes it believes are appropriate to meet the evolving needs of the RTO and the region, any such proposals or changes to existing agreements, which will be changes to the RTO's jurisdictional rate schedule(s) and contracts, will be subject to Commission review and approval under the FPA. The Commission will consider the merits of any changes to an approved RTO on a case-by-case basis. Interested parties will have the opportunity to comment on any such proposal. This process will enable all parties and the Commission to guard against proposed changes that are likely to stifle competition.

G. Transmission Ratemaking Policy for RTOs

We have concluded that the success of the Commission's efforts to have effective and efficient RTOs is dependent in large measure on the feasibility and vitality of the stand-alone transmission business. For that reason, and to promote economic efficiency, the RTO transmission ratemaking policies of the Commission are an important factor of RTO success. In light of the restructuring of markets and market institutions that is taking place, we now believe that it will be helpful to inform the industry about what we consider to be appropriate and inappropriate transmission pricing practices for RTOs, and about a framework for RTOs to propose efficient and fair pricing reform. Accordingly, we provide guidance below on a number of fundamental ratemaking issues.

We believe that it is critically important for RTOs to develop ratemaking practices that: eliminate regional rate pancaking; manage congestion; internalize parallel path flows; deal effectively and fairly with transmission owning utilities that choose not to participate in RTOs; and provide incentives for transmission owning utilities to efficiently operate and invest in their systems. In particular, the Commission encourages RTOs to develop and propose innovative ratemaking practices, particularly with respect to efficiency incentives. We therefore devote a significant portion of the discussion in this section of the Final Rule to performance-based regulation (PBR) and other RTO transmission ratemaking reforms.

In addition to the guidance offered here, we have added regulatory text (section 35.34(e)) with regard to PBR and other RTO transmission ratemaking reforms,[611] which now identifies a select list of innovative transmission rate treatments. The Commission will consider such innovative rate treatments for entities that file proposals under the new section 35.34 and that meet the minimum characteristics and functions required in the Final Rule. The Applicant must explain how the proposed rate treatment would help achieve the goals of RTOs, including efficient use of and investment in the transmission system and reliability benefits to consumers; provide a cost-benefit analysis, including rate impacts; and explain why the proposed rate treatment is appropriate for the RTO proposed by the Applicant. This means that filings under section 35.34(e) must be complete and fully explained; must demonstrate that the resulting rates are just, reasonable, and not unduly discriminatory or preferential; must identify how the rate treatment promotes efficiency and what benefits result; and must demonstrate that the rate treatment does not impede the RTO from meeting the minimum characteristics and functions required under this Final Rule. The Commission encourages properly developed transmission pricing proposals from RTOs that comply with the guidance set forth below and the amended regulatory text.

We agree with those commenters that urge the Commission to reform its transmission pricing policies to reflect new realities of the industry. For example, a number of commenters point to the unbundling requirements of Order Nos. 888 and 889, the vertical de-integration of generation and transmission for some utilities, the advent of wholesale and retail competition in energy markets, entry into markets of a range of new players, including independent generators and marketers, and other developments as a signal that the Commission's traditional cost-of-service ratemaking practices for transmission assets should be reevaluated. Some commenters suggest that the advent of competitive power markets necessitates a more robust transmission network as well as enhanced operating capabilities of the network, compared to the previous era of vertically integrated utilities providing service in monopoly franchise areas. They argue that the Commission's traditional transmission ratemaking practices are unlikely to support such a robust transmission network and enhanced operating capabilities.

[611] We have adopted and expanded the regulatory text proposed by Edison Electric Institute in its comments (*see* EEI, Appendix E).

To put our concerns about transmission pricing in perspective, the NOPR said that ''the Commission expects RTOs to reform transmission pricing, and in return we propose to allow RTOs greater flexibility in designing pricing proposals.'' [612] The NOPR also said that our willingness to provide flexibility in reviewing pricing proposals dates back to the Transmission Pricing Policy Statement, issued by the Commission in 1994. In the Policy Statement, we identified five principles that transmission pricing proposals should conform to, including the principle that pricing proposals should meet the traditional revenue requirement. In order that this principle not undermine innovative pricing proposals, the Policy Statement noted that non-conforming pricing proposals would be considered, but that such proposals would have to satisfy additional factors, *i.e.*, promote competitive markets and produce greater overall consumer benefits. In the five years since the Policy Statement was issued, we have approved five ISOs with innovative transmission pricing, but otherwise have received few innovative transmission pricing proposals. We believe that, as a general matter, sensible pricing reform that could promote competition and efficiency in other contexts will achieve maximum benefits only when applied on a regional, rather than a single-system basis. This is true because of the inability of single systems to capture such efficiencies, but sensible pricing reform is one of the efficiencies that will likely flow from RTOs. And while we do not think the Policy Statement has been an impediment to transmission pricing innovation, we now believe, based on the myriad comments we received, that the Commission should now provide greater specificity on appropriate transmission pricing reforms by RTOs.

The rationale for providing greater specificity on transmission pricing for RTOs and amending the regulatory text at this time is three-fold. First, we recognize that transmission pricing issues are some of the most complex issues facing the industry. Second, a potential barrier to the development of RTOs, at least RTOs that span multiple transmission systems, is the difficulty that stakeholders have had reaching consensus on transmission pricing. This is not surprising, given that transmission pricing reform to accommodate regional needs and usage patterns can affect what customers pay for transmission service and how transmission revenues are allocated among multiple owners of transmission within a region. Third, we are concerned that as we move to greater reliance on market forces, the incentives that market participants have to make efficient operating and investment decisions for both generation and transmission facilities are based in part on the price signals that flow from transmission pricing. That is, transmission pricing is a key determinant of the efficient operation of energy, ancillary service and balancing markets, and congestion management.

At the outset, we want to make clear that, contrary to the apprehensions of some commenters, the Commission is not proposing to ''bribe'' transmission-owning utilities to join an RTO. Rather, the Commission stated in the NOPR that it would consider innovative pricing proposals because we believed then, and now believe more strongly, that a reassessment of transmission pricing policy is warranted, given the fundamental changes in industry structure that have already occurred as well as those which may flow from the RTO Final Rule. In addition, as pointed out by Professor Joskow, delays in RTO formation occasion costs because of more limited competition in generation markets, and these costs may be avoided to the extent that the Commission considers transmission pricing reforms. Furthermore, as discussed below, since the costs of transmission are a small portion of total electric costs, getting transmission pricing right means that the industry will be able to capture significant net benefits from promoting competitive generation markets.

While the NOPR did not propose specific rules on transmission pricing reform, we believe it is now critical to provide further specificity to the industry. We recognize the need to establish clear and specific requirements for RTO development, provide certainty and clarity about our willingness to entertain transmission pricing reforms that are appropriate for RTOs, and assure utilities that they will not be penalized for RTO participation. To the extent consistent with ensuring that transmission rates are just, reasonable, and not unduly discriminatory, we believe transmission pricing disincentives to joining an RTO should be eliminated so that transmission-owning utilities will find RTO participation to be a dynamic business opportunity. Utilities that join RTOs should be accorded transmission pricing that reflects the financial risks of turning facilities over to an RTO and that reflects other changes in the structure of the industry. Those risks may increase or decrease in particular instances. At the same time, we wish to make clear that the Commission is very concerned about potential impacts of market restructuring on the customers in ''low-cost'' states, and the Commission therefore intends to monitor the effects of RTO formation on such customers, specifically the potential for cost-shifting effects of RTO pricing proposals.

Traditional transmission pricing approaches reflect the industry structure as it existed when Order No. 888 was issued: a vertically integrated industry where transmission systems were designed primarily to meet the needs of local loads. Our primary focus, both in terms of access and pricing was comparability; that is, all transmission users should receive access under rates, terms and conditions comparable to those the transmitting utility applies to itself to serve its own customers. RTOs reflect a somewhat different approach, in which the transmission system must also be designed and operated to meet the needs of regional markets. It is not unreasonable to expect that, as the transmission system is restructured to meet these changing needs, significant pricing reform may be needed as well. Indeed, since a properly developed RTO will be designing methods to support regional congestion management and regional expansion, transmission pricing reform is inevitable.

We caution that we do not view transmission pricing reform as a program designed for the sole purpose of enhancing the revenues of transmission owners at the expense of transmission customers. Nor are we abandoning the fundamental underpinnings of our traditional transmission pricing policies, *i.e.*, that transmission prices must reflect the costs of providing the service.[613] While many aspects of transmission pricing reform are labeled incentive pricing, many are aimed at eliminating disincentives to the efficient use and expansion of regional transmission grids to support emerging competition in generating markets.

We view transmission pricing reform, not only as an important component of how stand-alone transmission companies can become viable and efficient network businesses, but also as an important means for transmission-owning utilities which maintain ownership but cede control of their transmission assets to an RTO to capture

[612] FERC Stats. & Regs. ¶ 32,541 at 33,754.

[613] *See, e.g., Federal Power Commission* v. *Hope Natural Gas Co.,* 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co.* v. *Public Service Commission of West Virginia,* 262 U.S. 679 (1923).

the benefits of more efficient system operation and additional grid investment. We believe that the opportunities for pricing reform identified in this Rule should have no effect on an RTO's decision about how it will be structured. All RTOs, regardless of ownership structure, are therefore eligible to propose transmission pricing reforms that suit their strategic and economic objectives to the extent consistent with this Final Rule.

We also believe that the potential for any increase in transmission-related revenues available to transmission providers that are efficient and responsive in meeting the needs of their customers must be balanced by the potential for a decrease in profits if the transmission provider does not meet those needs. Moreover, a properly developed RTO can be expected to produce significant efficiencies, and we would expect that transmission owners, transmission customers and generation market participants will share in the economic benefits resulting from the efficient design and operation of the RTO.

As the industry begins the collaborative process of establishing RTOs, it is important that the Commission provide some certainty and specificity about the preferred types of transmission pricing reforms, and some certainty and specificity about the types of proposed transmission pricing reforms that appear more problematic. Accordingly, the remainder of this section discusses eight specific transmission ratemaking topics: pancaked rates; reciprocal waiving of access charges between RTOs; use of single system access charges; congestion pricing; service to transmission-owning utilities that do not participate in an RTO; performance-based regulation; other RTO transmission ratemaking reforms; and additional ratemaking issues.

1. Pancaked Rates

As described in the NOPR, the elimination of rate pancaking for large regions is a central goal of the Commission's RTO policy, and has been a feature of all five ISOs the Commission had approved. Rate pancaking occurs when a transmission customer is charged separate access charges for each utility service territory the customer's contract path crosses. The NOPR proposed that RTO tariffs not result in transmission customers paying multiple access charges to recover capital costs over facilities that it controls. The NOPR sought comments on the impact of the non-pancaked rate requirement on voluntary RTO formation because of abrupt rate changes. It also sought comments on how the regional configuration may relate to these potential rate changes.

Comments. The overwhelming majority of the comments favor the proposed prohibition on pancaked rates,[614] although some commenters express concern over cost shifting. Some commenters, such as Minnesota Power, suggest that the cost shifting effect of non-pancaked rates would discourage voluntary RTO formation.

Some commenters suggest alternative approaches to the strict non-pancaked rate described in the NOPR. For example, WPSC advocates the use of flow-based, distance-sensitive rates as a replacement for pancaked rates. Allegheny argues that removing rate pancaking can cause disruptive shifts in rates and revenue requirements which are solved only temporarily with transitional rates. Allegheny proposes its form of locational marginal pricing method to solve this problem. NSP favors non-pancaked rates but notes that rates for the high-voltage system that differ from those for the low-voltage system may be an effective long-term rate strategy. MidAmerican recommends that the prohibition against rate pancaking be changed to allow transmission owners to charge a home-zone rate based on local cost determination and a wide-area charge outside the home area. MidAmerican argues that this approach would minimize cost shifting. The pancaked rate prohibition would change to: ''promote wide-area transmission rates with due consideration to shifting of costs among transmission service providers and between state and federal delivery rates. Finally, Williams recommends that the Commission also consider other pricing methods such as those based on mileage or network usage and market-based rates, where possible, because it considers cost of service rates inefficient and unresponsive to the market.

A few commenters question an absolute prohibition against pancaked rates. AEP and Florida Power Corp. warn that a strict prohibition against pancaked rates may, at times, work against efficient solutions. There should not be a strict prohibition without regard to size or locational factors. Florida Power Corp. argues that this approach is consistent with the Commission's Transmission Pricing Policy Statement. Customers of both AEP and Florida Power Corp. dispute this view.[615] Southern Company notes that an absolute prohibition against pancaked rates may hurt retail customers whose rates are supported by transmission revenue. Transmission owners should be assured in the final rule that they will be able to recover their full revenue requirement in the face of any pancaked rate prohibition. The Commission should, according to Southern Company, also clarify that a prohibition against pancaked rates does not prevent the use of zonal or other distance-sensitive rates. Desert STAR argues that a single region-wide rate may not be appropriate in a large region with legitimate cost differences among companies, and suggests that license plate rates may mitigate cost shifting but will not always eliminate it.

Commission Conclusion. In the NOPR, we described the elimination of rate pancaking as a central goal of our RTO policy. After receiving comments on the subject, mostly in favor of the proposed prohibition, we affirm that the RTO tariff must not result in transmission customers paying multiple access charges to recover capital costs.[616]

Except for transactions within the ISOs now in place, transmission customers are faced with additional access charges for every utility border they cross. The distances need not be great to be assessed two, three or more access charges for a single transaction. This duplication can severely restrict the area in which generation can economically be secured. A main reason that an RTO can expand the marketplace for generation to a large region is that an RTO can implement non-pancaked rates for each transaction. A wider area served by a single rate means more generation is economically available to any customer which means greater competition for energy.

Some commenters warn that a blind adherence to non-pancaked rates can produce inefficiencies in some circumstances. Some argue that large distances and special conditions can add to transmission costs in a way not reflected in single system rates. They would leave open the option for distance-sensitive rates or completely new rate innovations that may not fit the strict definition of a non-pancaked rate. We are sensitive to some of these concerns, but we do not view a policy requiring non-pancaked rates as posing the problems that some commenters

[614] *See, e.g.,* NASUCA, PJM, LG&E, Industrial Consumers and WEPCO.

[615] *See* New Smyrna Beach and Coalition of Alliance Users.

[616] Section 35.34(k)(1)(ii). However, see the discussion below regarding service to transmission-owning utilities that do not participate in an RTO.

describe. We take this opportunity to reaffirm that we will continue to be receptive to distance-sensitive rates and other rate features that can be supported.

2. Reciprocal Waiving of Access Charges Between RTOs

The elimination of pancaked rates within an RTO was intended to increase the efficiency of trade in that region. The NOPR furthered that concept by encouraging RTOs to agree among themselves to waive access charges on a reciprocal basis for transactions that cross RTO borders. If accomplished, this would have the effect of increasing effective trading areas. The NOPR sought comments on how the Commission could facilitate reciprocal waivers of access charges, and whether there are other impediments to inter-regional trade.

Comments. A majority of the commenters support the concept of a reciprocal waiver of access charges to encourage inter-regional trade.[617] Of those who support waivers, some, including Duke and SRP, specifically recommend that waivers be voluntary. Some supporters of waiving access charges note that it is not just the pancaked charges that inhibit inter-regional trade but also variations in business practices and procedures between RTOs. These commenters[618] recommend that the Commission ensure that such incompatibilities not be allowed to hamper trade between RTO regions.

Several commenters, both supporting and opposed to waiver of access charges, warn that the waivers proposed in the NOPR can cause cost shifting. Duke argues that cost shifting can be remedied by the structure of the rate. DOE and First Energy also express concerns about cost shifting. Southern Company generally opposes waivers of access charges unless transmission owners' revenues are protected.

Some commenters oppose waiving access charges between RTOs for reasons other than cost shifting concerns. South Carolina Authority claims that reciprocal agreements between RTOs waiving access charges are discriminatory and that independent monitoring groups would be needed to prevent gaming of reciprocity agreements. CP&L argues that waivers create a bias to sell outside of the RTO. Tri-State proposes the use of distance-sensitive export pricing mechanisms instead of waivers.

PP&L Companies claim that inter-regional trade solutions should be arrived at through a collaborative effort of stakeholders. NECPUC and Desert STAR argue that the Commission should grant deference to participants' solutions for inter-regional trade. Florida Commission argues that the Commission should wait until intra-regional trade barriers are dismantled before dealing with inter-regional trade.

Commission Conclusion. We asked in the NOPR for comments on the policy of allowing RTOs to reach reciprocal agreements to waive access charges for transmission that crosses an RTO border. Most commenters supported the approval of such waivers and some asked the Commission to further support inter-regional trade by requiring uniform practices and procedures among RTOs. Some commenters maintain that incompatible or varying procedures between RTOs can be as dampening to inter-regional trade as multiple rates.

We will continue to encourage reciprocal waivers of access charges between RTOs as long as they are reasonable in terms of cost recovery, cost shifting, efficiency, and discrimination. We also encourage terms and procedures that are compatible from region to region to the extent appropriate. Accordingly, we have added an RTO function to integrate reliability and market interface practices with other regions, as discussed above.

3. Uniform Access Charges

Each ISO approved by the Commission has struggled with the problem of cost shifting among the various individual transmission owners that make up the ISO. A single access rate would mean that the customers of low-cost transmission providers would see a rate increase and high-cost transmission providers would be concerned about not meeting their revenue requirements. The potential for cost shifting has been a stumbling block for several regions seeking to establish regional transmission organizations.

The Commission has allowed a flexible approach to this problem, and in each ISO approved by the Commission to date the solution has been to adopt a "license plate" rate for a transitional period of five to ten years before moving to a single uniform access charge. A license plate rate provides access to the regional transmission system at a single rate although that rate may vary based on where the customer is located.[619] The NOPR proposed to continue to employ a flexible approach, including the use of license plate rates. The NOPR requested comments on whether the license plate approach is appropriate for the long term.[620]

Comments. A clear majority of commenters favors the use of license plate rates in general, with a nearly even split between those that would allow license plate rates only for a transitional period[621] and those that would allow them as a permanent feature.[622] Of the approximately 64 commenters who addressed this subject, only about nine were clearly opposed to license plate rates for either the long term or for a transitional period. And several commenters advocate the use of license plate rates as a general concept but did not address directly the NOPR's question concerning their long-term use.[623]

Several commenters argued that the use of license plate rates should be for a transition period roughly coincident with the phase-in of retail competition. For example, Duke argues that license plate rates avoid cost-shifting, and will therefore make it easier for companies to collect their retail revenue requirements in jurisdictions without retail competition, where state regulators may disallow higher transmission rates.

Commenters that support license plate rates as a long-term solution argue that license plate rates are an aid to RTO formation.[624] SoCal Edison claims that license plate rates avoid cost shifts, are administratively more efficient, provide a basis for efficient transmission operation, and provide incentives for system expansion. SoCal Edison favors their use in the long term.

Of those opposed to license plate rates in general, some suggest a different pricing methodology. CMUA prefers an integrated, two-part rate. The first part of the rate reflects the revenue requirement of the overall RTO (principally above 200 kV) and the second part reflects the local systems to the extent used. CMUA argues that license plate rates do not follow the rules of cost causation, do not promote needed enhancements and do not promote comparability in rates. Minnesota Power recommends a two-part rate with a demand component to

[617] *See, e.g.,* Sithe, WPSC, Minnesota Power, Ohio Commission, and Midwest ISO Participants.

[618] *See, e.g.,* Ontario Power and Oregon Office.

[619] Consider that registering a car in one state, paying that state's fees, and obtaining a license plate from that state, allows that car to be driven on the roads and highways of all other states.

[620] FERC Stats. & Regs. ¶ 32,541 at 33,754.

[621] *See, e.g.,* Montana Commission, Oglethorpe, Tri-State, FirstEnergy, Alliance Companies, AEP and DOE.

[622] *See, e.g.,* Allegheny, Industrial Consumers, Northwest Council, APS, Desert STAR and SPP.

[623] *See, e.g.,* Kentucky Commission, Gainesville, Big Rivers, Puget and Ontario Power.

[624] *See eg.,* East Kentucky and PJM.

collect fixed costs and a variable component for losses. WPSC advocates the use of flow-based, distance-sensitive rates rather than license plate rates. APPA claims that license plate rates do not go far enough. A four part approach is suggested in their place: assure recovery of revenue requirement; honor existing contracts and phase in regional rates; sub-functionalize the grid by voltage; and, once trusted RTOs are in place, allow congestion rates above embedded costs and non-congestion rates below, all subject to a revenue requirement true-up. RECA recommends that zones for transmission access charges be formed based on cost and other differences, not on existing service areas. SMUD claims that Cal ISO's license plate rate encourages inefficient operation.

Some commenters provide more general reactions to the cost shifting problem. Wyoming Commission recommends that the Commission not codify a specific approach to license plate rates and other measures with cost-shifting ramifications but rather defer to regional and state processes to establish guidelines within a region. PSNM is concerned about the impact of the loss of existing contracts on its license plate rate calculation. Manitoba Board is concerned about shifting costs to low-cost, transmission-dependent areas. Platte River does not want its low costs averaged with higher cost systems. United Illuminating encourages the Commission to continue its flexibility in permitting different approaches in the recovery of sunk costs. Aluminum Companies argues that the Commission needs to offer more guidance on cost shifting and that rate increases due to cost shifting should be constrained to the benefits involved. Further, cost shifts should not be allowed unless competition is fostered.

Commission Conclusion. We conclude that the Commission should continue to provide flexibility with respect to RTO proposals for allocation of fixed transmission cost recovery. The Commission will permit RTO proposals to use license plate rates, as defined above, for several reasons. First, commenters overwhelmingly support the use of license plate rates, and demonstrated convincingly that problems associated with cost-shifting are not easily resolved by means other than the use of license plate rates. Second, the Commission is concerned that the potential for cost-shifting could act as an impediment to RTO formation, thereby denying all stakeholders the benefits that come from RTO membership.

Moreover, although license plate rates are not necessarily an ideal method for fixed cost recovery, we note that all ISOs have sought approval from the Commission for license plate rates, at least during their startup phase. No commenter has provided convincing evidence that the use of license plate rates by existing ISOs produces significant harms, although several commenters suggest various rate designs, including multi-part rates, as alternatives to license plate rates.

Although commenters overwhelmingly support the use of license plate rates, they are split on whether such rates should be used only for a transitional period, or whether the Commission should allow them as a permanent feature. This is a difficult issue. On the one hand, we are reluctant to require RTOs to suspend use of license plate rates after some arbitrary date certain at which time they will be required to transition to single system access rates; on the other hand, we are reluctant to announce generically that license plate rates may be a permanent feature of an RTO. Furthermore, the use of license plate rates could depend on idiosyncratic facts, *e.g.,* the geographic makeup of the RTO, or the transmission cost differences in various subregions of the RTO.

We therefore believe that it is appropriate to allow RTOs to propose the use of license plate rates for a fixed term of the RTO's choosing. However, RTOs that propose the use of license plate rates must make clear how transmission expansion will be priced, that is, whether license plate rates or some other mechanism will be applied to the cost of new transmission facilities, and how such pricing affects incentives for efficient expansion. In addition, we will require that before the end of the fixed term, the RTO must complete an evaluation of fixed cost recovery policies based on the factual situation of the particular RTO, and file with the Commission its recommendations on any changes that should be instituted. We emphasize that we are not requiring that the RTO continue or abandon the use of license plate rates at that time, but we will require the RTO to justify its choice to continue or discontinue using license plate rates, or otherwise change the method for fixed cost recovery. We believe that this approach provides participants in RTOs significant flexibility, and is consistent with the principles articulated in the open architecture requirement for RTOs.

4. Congestion Pricing

Congestion pricing and congestion management are closely related. Comments on these issues have been treated jointly, and are summarized above in the discussion of congestion management.

Commission Conclusion. With respect to congestion pricing, the Commission emphasized that it intends to be flexible in reviewing pricing innovations, and sought comments on what specific requirements, if any, best suited the Commission's RTO goals. A number of commenters agreed with the Commission's conclusion in the NOPR that ''markets that are based on locational marginal pricing and financial rights for transmission provide a sound framework for efficient congestion management.'' [625]

We reemphasize the basic principles for congestion pricing articulated in the NOPR, *i.e.,* that proposals should ''ensure that the generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and limited transmission capacity should be used by market participants that value that use most highly.'' [626]

We recognize that congestion pricing, especially when complex problems associated with parallel path flows are addressed, is in its infancy. Rather than prescribe a specific method, we encourage experimentation with reasonable congestion management techniques. We would expect that such experiments be consistent with the open architecture requirements of the rule, and that information from such experiments be made widely available to all interested parties, so that other RTOs can learn from each others' experience.

5. Service to Transmission-Owning Utilities That Do Not Participate in an RTO

The Commission asked commenters to discuss the treatment by an RTO of a non-participating transmission owner in a region if the transmission owner does not participate in its region's RTO.[627] For example, we asked whether it would be appropriate to allow RTO members to provide transmission service at individual system rates to non-participating transmission owners located in the RTO region thereby denying non-participants the benefits of non-pancaked transmission rates.

Comments. Of those commenters that generally support the proposed strategy,

[625] FERC Stats. and Regs. ¶ 32,541 at 33,742.

[626] *Id.* at 33,754–55.

[627] *Id.* at 33,759.

most argue that non-participants should not enjoy the benefits of non-pancaked rates.[628] PG&E submits that the reasoning the Commission applied in Order No. 888 applies here (*i.e.,* in Order No. 888, the Commission rejected the claim that a reciprocity requirement required explicit Commission jurisdiction over the transmission customer finding that, as a matter of fairness, a public utility providing open access through a non-discriminatory tariff deserved the right to obtain comparable access over the transmission systems of its customers). Empire District is particularly concerned that utilities on the border of an RTO may receive many advantages of the RTO without accepting any of the burdens of participation, yet at the same time make it more difficult for competitors to service its load by staying out of the RTO.

Other commenters are conditional in their support. For example, Oneok wants the Commission to draw a hard line on non-participation and be willing to employ negative incentives; however, Oneok points out that denial of non-pancaked rates will be more costly to marketers and consumers. South Carolina Authority suggests that the Commission consider the extent to which the transmission owner is actually able to participate in an RTO before permitting denial of RTO service under non-pancaked rates. In the case of publicly owned utilities, there may be restrictions in the enabling act or charter, the applicable state constitution or the utility's bond covenant that effectively prohibit it from participating in a particular RTO. This would also apply if the RTO is not the product of the ''region's RTO'' involving all stakeholders in the designated region but is a business entity designed to advance the financial objectives of particular sponsors. Similarly, SPRA argues that, in the event that it is unable to immediately join an RTO, the RTO should recognize that SPRA has an OATT that provides for comparable treatment to the RTO. And New Smyrna Beach states that, although denial of non-pancaked rates to nonparticipants has merit, it may be a moot issue in Florida where FP&L's transmission is so extensive that pancaked rates would be a more costly alternative for marketers and consumers of electricity.

Other commenters believe the proposal is a flawed concept or otherwise oppose it. Avista and PPC argue that it is not appropriate to allow an RTO to provide transmission service at individual system rates to non-participating transmission owners as such a policy would deny them the benefits of non-pancaked rates and defeat the central goal of its proposal. Metropolitan concurs that non-participating transmission owners should share in the benefits of non-pancaked rates. Southern Company and CP&L claim that the Commission cannot punish utilities that find it in the best interests of their stakeholders not to join an RTO. SMUD believes that RTOs must provide nondiscriminatory access to transmission it controls at cost-based rates to all customers, since they contribute to the RTO's cost recovery. SMUD argues that the Commission, through its NOPR has, in essence, found that pancaked rates are not just and reasonable and that they should be corrected; thus, the Commission cannot allow an RTO to charge pancaked rates in violation of the FPA section 205 prohibition on unjust or unreasonable rates.

Snohomish, Turlock, Big Rivers and Dairyland all make similar arguments—charging higher pancaked rates to utilities that do not participate in the RTO is patently unfair, violates the Commission's duty to eliminate discriminatory rates, and would penalize consumers of customer-owned utilities who have no practicable choice about whether to participate in the RTO. Dairyland says that this could open the door to creation of RTOs that purposely do not accommodate non-public utilities. SRP posits that imposition of pancaked rates on non-participants in an RTO would effectively turn the Commission's stated policy goal of voluntary participation into an RTO mandate inviting years of litigation.

Two state commissions question the effectiveness of pancaked rate sanctions against non-participants. Indiana Commission contends that a recalcitrant utility may not perceive pancaked rates as detrimental and may not feel compelled to join an RTO. Illinois Commission feels that imposition of penalties involving restricted access to RTO transmission rates would either be self-defeating for the Commission or detrimental to the electricity consumers of the affected utility. In its view, the solution to this conundrum is for the Commission to abandon its unworkable voluntary approach to RTO participation, and utilize its authority under FPA sections 205 and 206 and examine its authority under FPA sections 202(a), 211 and 212 to mandate participation. However, Nevada Commission submits that the Commission must ensure that a transmission-owning utility that refuses to join an RTO should not be allowed to derive any economic benefit from the existence of RTOs.

ISO commenters have diverse views on this issue. Desert STAR argues that a blanket ban on prohibiting a party that does not join an RTO from deriving any benefit from the RTO whatsoever may be too broad an approach. NYPP, citing *Associated Gas Distributors* v. *FERC*[629] and *Richmond Power & Light* v. *FERC*[630] for the proposition that the Commission cannot achieve indirectly what it cannot do directly, submit that the Commission cannot impose any coercive measure on or deny benefits to utilities that do not participate in an RTO. In addition, NY ISO argues that previously approved ISO's transmission-owning members should be eligible for whatever RTO participation incentives and benefits are ultimately adopted in this proceeding. On the other hand, PJM/NEPOOL Customers support denial of non-pancaked transmission rates to nonparticipants.

Canadian entities generally oppose imposition of pancaked rates against non-participants. Canada DNR contends that a decision not to participate in an international RTO by a Canadian jurisdiction should not place entities in that jurisdiction engaged in trade with the U.S. at a disadvantage relative to U.S. RTO participants. BC Hydro concurs that the decision to join an RTO should not be made a prerequisite for participation of Canadian provincial utilities or their affiliates to participate in the U.S. electricity market. CEA observes, however, that Canadian utilities see access to the U.S. market as a significant business opportunity that requires a transparent and open bulk transmission system operating in both directions. Grand Council *et al.* submits, however, that applying no penalties or incentives to Canadian utilities, while giving them unfettered access to U.S. markets without being subject to corresponding obligations, is inconsistent with the RTO concept. And H.Q. Energy Services submits that, if the Commission decides not to require RTO participation, it should strongly encourage voluntary participation by denying certain benefits such as the use of the system-wide tariff to nonparticipants.

Commission Conclusion. Regarding the question raised in the NOPR about whether a non-participating transmission owner in an RTO region should receive all the benefits of the RTO in its region, we share the concerns

[628] Montana-Dakota, Allegheny, PG&E, Tri-State, PNGC and Empire District.

[629] 824 F.2d 981, 1024 (D.C. Cir. 1987).

[630] 574 F.2d 610, 620 (D.C. Cir. 1978).

of most commenters that transmitting utilities may receive the benefits of an RTO in its region without accepting any of the burdens of participation in the RTO. Accordingly, where a transmission customer of an RTO or the customer's affiliate owns, controls or operates transmission in the RTO's region, and is not participating in that particular RTO, we intend to permit that RTO to propose rates, terms, and conditions of transmission service that recognize the participatory status of the customer.

We do not intend that every such proposal will necessarily be accepted by the Commission. Each RTO must justify any proposal on a case-by-case basis. The proposal should recognize the various situations of non-participating transmission owners. As pointed out by commenters, some transmission owners may face legal obstacles to participation that may need to be taken into account in the proposal.

It is not our intent to permit an RTO to apply such a proposal to a non-participating transmission owner in another region. As discussed above, Empire District expressed concern about whether this provision would apply to a non-participating owner "on the border" of an RTO. We would permit an RTO to argue that the non-participant should be part of its RTO region based on engineering or other objective criteria.

An RTO will provide several benefits for parties in the region, including elimination of individual system rates. We asked in the NOPR whether it would "be appropriate to allow RTO members to provide transmission service at individual system rates to non-participating transmission owners *located in the RTO region.*" (emphasis added)[631] SMUD argues that the Commission in its NOPR has found, in effect, that individual system rates are not just and reasonable and so cannot allow transmission-owning utilities in an RTO to charge individual system rates.

SMUD is incorrect. We have not made a generic determination that individual system rates are not just and reasonable in an RTO region. A non-participating public utility transmission owner in an RTO region may itself file a single company rate and argue that it is just and reasonable for use by its neighbors who join the RTO.

Instead of making a generic determination about these matters, we will permit an RTO and its transmission-owning public utility members to make the case that it is just and reasonable to charge individual system rates to a transmission customer who is a non-participating transmission owner in its RTO region. We will decide each RTO proposal on its merits.

6. Performance-Based Rate Regulation

The NOPR suggested that, once RTOs are formed, performance based regulation (PBR) can facilitate good grid operation.[632] We noted that PBR can incorporate price/revenue caps, price incentives, or performance standards. The NOPR sought comments on how PBR should be applied to an RTO and whether it should be voluntary.

Comments. The vast majority of commenters favor PBR of some form to promote efficient operations by RTOs.[633] And most commenters that favor PBR specifically state that PBR should be voluntary for RTO participants.[634]

Professor Joskow recommends that the Commission promote the view that PBR will eventually be required. He suggests that there is sufficient experience with PBR, such as in England and Wales. He argues that PBR should be based on a standard price cap that focuses not only on direct transmission service costs, but also focuses on the cost of congestion management, losses, ancillary services, reactive power, and connection of new generators. EEI notes that a price cap, based on a reasonable ROE revenue requirement, is the most widely used method. EEI argues that price caps reduce rate cases, give an incentive to improve productivity, and share productivity savings with customers. Brattle Group does not propose a specific PBR scheme but says that, at this point, approval should be case-by-case. Care should be taken that a PBR is not based on a single element, causing distortions elsewhere.

Other supporters have specific comments regarding the implementation of PBR. Entergy recommends that the Commission provide more specific guidance on the use of PBR. DOE warns that PBR should not be allowed to prevent a PMA that is a part of an RTO to under-recover its revenue requirement. New Smyrna Beach and Oneok only support PBR if there is a downside as well as an upside potential associated with transmission performance. Allegheny states that the Commission must settle on a definition of performance, the performance criterion should be economic reliability, the owner must have an opportunity to recover investment, the Commission should recognize that some aspects of performance will be outside of the control of the RTO, and the particular PBR rate calculation should be considered on a case-by-case basis.

A number of commenters recommend that PBR not be instituted immediately upon the formation of the RTO. California Board, Trans-Elect, and WPSC maintain that time is needed to establish base year benchmarks. PG&E and APPA say that PBR should be set aside until the RTO is up and functioning and Arkansas Consumers and Wyoming Commission argue that the RTO should first demonstrate that it can and will provide reliable and non-discriminatory service before PBR is established.

At least eight commenters were opposed to PBR for RTOs as a Commission policy. Industrial Consumers, Williams, and CMUA do not think that PBR can be effective in promoting efficiency in the operation of RTOs. Salomon Smith Barney and East Texas Cooperatives believe that RTOs will be able to game the system and take advantage of PBR. PJM/NEPOOL Customers, Lincoln, and NASUCA argue that PBR should not be allowed for RTOs because they are unnecessary. NASUCA is also skeptical of PBR for RTOs because some areas where performance is important are not under the RTO's control. NJBUS argues that PBR will not put a stop to transmission discrimination.

NEPCO *et al.* disagree with those commenters who oppose PBR.[635] PBR is effective, as shown in the United Kingdom, and they are not "bribes" given freely to transmission owners. Enron/APX/Coral Power does not agree with NASUCA and California Board that there is not enough experience on which to base PBR. According to Enron/APX/Coral Power, there is a large amount of experience in regulating transmission plus a lot of experience with the ramifications of EPAct.

A few additional commenters neither strongly support nor oppose PBR, but offer specific comments about PBR use. Project Groups recommends that the Commission construct a way to de-couple revenues from transmission rates so that efficient transmission service rather than total throughput determines revenue. Florida Commission states that questions as to the advisability and particulars of a PBR mechanism should be left to regional solutions that have the endorsement of the state regulatory

[631] FERC Stats. & Regs. ¶ 32,541 at 33,759.

[632] *Id.,* at 33,755.

[633] *See, e.g.,* EPSA, PJM, Los Angeles, Georgia Transmission, Illinois Commission, Pacific Corp and Desert STAR.

[634] *See, e.g.,* Florida Power Corp., MidAmerican, Tri-State, FirstEnergy, Alliance Companies, Duke and PGE.

[635] *See, e.g.,* APPA, Minnesota Power and CMUA.

bodies. Big Rivers states that PBR is inappropriate for cooperatives and public power utilities. WEPCO believes that RTOs should be not-for-profit and that PBR should be available only to the for-profit transmission owner. Metropolitan is concerned that PBR might cause RTOs to neglect needed expansions and upgrades and jeopardize reliability.

Commission Conclusion. At the outset, we think it is important to emphasize that PBR is far from a new concept. Over the last 10 to 20 years, a significant amount of research, primarily by economists, has been done regarding the conceptual basis of, and efficient designs for, PBR.[636] This research addresses its use in the electric utility industry as well as other regulated industries. It is also important to note that the Commission has been receptive to PBR proposals, at least since issuance of the Policy Statement on Incentive Regulation in October 1992. In that Policy Statement, we provided guidance to public utilities as well as natural gas and oil pipelines considering proposing some form of PBR.[637] Although the Policy Statement invited public utilities to develop and file incentive regulation proposals, the Commission has not received any proposals from public utilities.[638]

The Commission's current interest in PBR stems from the proposition that PBR will allow the Commission to rely on market-like forces, to the maximum extent possible, to create incentives for RTOs to efficiently operate and invest in the transmission system. This does not mean that we expect that transmission services will be provided in competitive markets any time soon, or at all. We recognize that transmission service will retain most or perhaps all of the characteristics of a natural monopoly for the foreseeable future, and that some type of explicit price regulation will therefore be required to prevent monopoly abuse. But we believe that PBR, especially if accompanied by explicit and well-designed incentives, may provide significant benefits over traditional forms of cost-of-service regulation. We believe this view of PBR is entirely consistent with other initiatives taken by the Commission, such as Order Nos. 888 and 889, to promote competitive power markets, and given the impracticality of competitive transmission markets, to rely on market-like forces to the maximum extent possible.

Before providing further specificity on PBR, it is useful to restate the overarching concerns of commenters. A large number of commenters support the use of PBR, and many of them, as discussed above, believe that PBR and other forms of incentive regulation will significantly enhance the incentives RTOs have to make efficient operating and investment decisions. For example, Professor Joskow notes:

> It is very important for the Commission to adopt regulatory mechanisms that provide transmission owners and operators with powerful economic incentives to operate transmission networks efficiently and to invest the resources necessary to expand their capabilities efficiently. These incentives should be an integral component of a performance-based regulatory (PBR) framework for the regulation of transmission rates that rewards transmission owners for achieving these objectives and penalizes them for failing to do so.[639]

On the other hand, a somewhat smaller group of commenters, mostly transmission customers, oppose the use of PBR. They express doubts about whether PBR will provide good incentives for RTOs to operate and invest efficiently. They are also concerned that PBR design is so difficult that RTOs will easily game the system, which will likely result in higher revenues for RTOs and therefore higher prices for transmission services for all transmission customers.

Commenters describe a wide array of PBR mechanisms, including some relatively unsophisticated proposals and others which are analytically complex. For example, a number of commenters have proposed that the Commission entertain transmission rate moratoriums, *e.g.*, where transmission rates are locked into their current levels for a limited period of years. To the extent the transmission provider can achieve any transmission costs savings, these would be retained by the transmission provider. In this sense, it falls within the concept of PBR.

It is argued that this rate treatment may promote the establishment of independent transmission companies because it provides the certain revenue stream that is needed to obtain financing for the purchase of transmission systems from existing owners. It is also argued that this approach is analogous to a hold harmless commitment for existing customers which may simplify the efforts of those state regulators who value transmission rate certainty during their conversion to retail choice. This approach would also reduce litigation at the Commission during the moratorium.

Finally, if the rate level selected takes into account the existing transmission component of bundled retail power rates, it addresses the concern expressed by many that one deterrent to participation in RTOs is the fear and uncertainty that transferring retail transmission services from state to Commission jurisdiction leads to reduced revenues.

Other commenters suggest that the essence of PBR is to set cost and performance benchmarks and then reward or penalize an RTO based on performance relative to those targets. Clearly, such an approach presents significant analytical challenges. Ideally, an RTO's cost and operating performance can be compared with other, similar entities. One benefit of setting such targets is that it overcomes the asymmetric information problem, *i.e.,* a transmission service provider will usually have better knowledge of the potential efficiency gains than will regulators. Benchmarking performance helps reduce the information imbalance.[640]

We have carefully considered all of the comments about PBR. We conclude that the Commission should encourage RTOs to consider use of PBR, although we recognize the difficult analytical challenges that RTOs will face. To facilitate such consideration, we are providing additional specificity on PBR. We address several threshold procedural issues, and articulate additional design principles that should provide a framework for RTO consideration of PBR.

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[636] *See, e.g.,* Paul Joskow and Richard Schmalensee, Incentive Regulation for Electric Utilities, *Yale Journal of Regulation,* Vol. 4 at 1–49 (1986); Sanford Berg and Rajiv Sharma, Techniques for Assessing Firm Efficiency, University of Florida Public Utilities Research Center Working Paper (June 1999); Peter Navarro, Seven Basic Rules for the PBR Regulator, *Electricity Journal* at 24–30 (April 1996); G. Alan Comnes, Steven Stoft, *et al.*, Six Useful Observations for Designers of PBR Plans, *Electricity Journal* at 16–23 (April 1996); Lorenzo Brown and Ingo Vogelsang, Incentive Regulation: a Research Report, Federal Energy Regulatory Commission, Office of Economic Policy, Technical Report 89–3 (1989); and Jean-Jacques Laffont and Jean Tirole, A Theory of Incentives in Procurement and Regulation, MIT Press (1993).

[637] The Policy Statement articulated five regulatory standards: (1) incentive ratemaking must be prospective; (2) participation must be voluntary; (3) incentive mechanisms must be understood by all parties; (4) benefits to consumers must be quantifiable; and (5) quality of service must be maintained.

[638] We note that PBR mechanisms have been widely used by state regulators and the FCC as applied to the U.S. telecommunications industry. *See, e.g.,* John Kwoka, Implementing Price Caps in Telecommunications, *Journal of Policy Analysis and Management,* Vol 12, No 4 at 726–52 (1993).

[639] Professor Joskow at ES–iv.

[640] We note that there have been some early attempts to compare the relative cost and performance of ISOs in the U.S. *See, e.g.,* California ISO, ''A Comparative Analysis of Operating ISOs in the United States'' (Oct. 15, 1998).

A first threshold issue is whether the Commission should require that RTOs use PBR or whether it should be voluntary. There is almost no support for making PBR mandatory, and we therefore will not require RTO filings to include PBR proposals, although we encourage such proposals.

A second threshold issue is what types of RTOs are eligible for PBR. As discussed above, some commenters argue that PBR is not appropriate for cooperatively-owned and publicly-owned transmission owning utilities. Similarly, other commenters argue that PBR is appropriate only for profit-making RTOs. We conclude that, although the application of PBR may vary according to the type of RTO, there is no reason to limit the applicability of PBR to certain members or types of RTOs. The Commission welcomes RTO filings with PBR proposals from any source. For example, in the context of an ISO or a tiered ISO/transco that has been described by some commenters, the activities that contribute to performance may be shared between the RTO and the transmission owners. This does not invalidate the use of PBRs; however, the RTO design would simply ensure that the rewards and penalties associated with activities performed by transmission owners flow through to the owners to achieve the desired result.[641] In addition, we see no impediment to the use of PBR to provide incentives for efficient behavior by non-profit RTOs. We note that some existing ISOs have in place performance incentives for some of their managers, and such an incentive scheme may have application for RTOs which do not own the transmission assets they control.

A third threshold issue is how PBR proposals will be formulated and when they will be filed. The Commission recognizes that PBR design involves highly complicated issues, and that there is the possibility that a bad PBR proposal can result in lower quality transmission service, at higher costs, compared with service that might prevail under traditional ratemaking practices. One key element in the process of designing a PBR proposal would be to ensure adequate input from all stakeholders. We believe that the best PBR designs will emerge when all stakeholders have an opportunity for input, even if a filed PBR design does not represent full consensus. We therefore conclude that RTOs that wish to implement PBR need not necessarily file the PBR proposal at the time the RTO makes its compliance filing if more time is needed to negotiate among stakeholders the details of a well-designed PBR. Some commenters suggest that an additional consideration in allowing delayed filings of PBR is the need to evaluate operating experience of the RTO before appropriate benchmark measures for PBR can be developed.

The Commission also believes it is appropriate to provide additional specificity on what constitutes good PBR design. We continue to endorse the regulatory standards included in the Incentive Regulation Policy Statement, described above. And we note that in some regions, certain types of PBR mechanisms may be better suited than others. For example, where there are already state-imposed rate moratoriums, continuation of such programs after RTO formation may be an appropriate PBR approach. Alternatively, a transmission rate moratorium based on the existing rate level may be appropriate for a transitional period during RTO formation.[642] Similarly, in an area that has experience with a particular performance-based mechanism, extension and perhaps refinement of such a program after RTO formation may be the most appropriate policy.

We encourage RTOs to file fully documented PBR proposals that are consistent with the amended regulatory text. PBR proposals should include a detailed explanation of how the PBR mechanism will work, as well as all of the information necessary for the Commission and all market participants to evaluate the benefits and costs of implementing the PBR mechanism.

Based on the comments we received in this docket, as well as our understanding of international[643] and state experience with incentive regulation, we expand on the considerations for PBR addressed in the amended regulatory text by offering the following additional principles for RTOs to consider in designing PBR proposals.

PBR should not be applied piecemeal. To the extent possible, PBR programs should focus on the entire operation of the RTO, rather than smaller parts of the operation. Commenters caution that PBR programs that focus narrowly, *e.g.,* only on the cost aspects of RTO operations, may result in inattention by the RTO to the quality of service offered. Similarly, a focus on only one aspect of costs, *e.g.,* short-run costs, may result in reduced costs for that single aspect, but higher total costs for the RTO.

PBR should encompass both rewards and penalties. Although some PBR designs employ either rewards or penalties, but not both, most commenters suggest, and the Commission agrees, that the most effective and most fair designs will likely encompass both. One rationale for this is that it is not always clear what incentives an RTO will respond to, and therefore the prospect of higher revenues as well as the threat of lower revenues may induce an RTO to provide the best possible performance. An additional rationale is that under the FPA, the Commission is required to set rates for transmission service at just and reasonable levels. To the extent that rates may vary within a range—both up and down—as a function of RTO performance, this statutory requirement may be better satisfied.

PBR rewards and penalties should create incentives for an RTO to make efficient operating and investment decisions, and should not compromise system reliability. A significant concern in any PBR application is the possibility that incentives will distort RTO decisionmaking. For example, commenters caution that an RTO may manage congestion through a combination of generation redispatch and investment in transmission infrastructure, and that poorly designed PBR mechanisms could distort RTO decisionmaking toward the most profitable, rather than the least-cost, solution, or toward an approach that inappropriately reduces system reliability. An additional concern is that PBR mechanisms may create bias with respect to the trade-off between investment in generation and transmission, or in siting generation and transmission facilities in the most efficient places on the grid.

The benefits of PBR should be shared between the RTO and its customers. The Commission believes that as a matter of fairness, the efficiency gains occasioned by PBR should be shared. This will involve difficult analytical issues, including identifying efficiency gains,

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[641] For example, PJM states that it can facilitate the application of PBRs to its transmission owners by using the stakeholder process to set the performance parameters and, once the parameters are in place, to independently evaluate the transmission owners' performance and apply the PBR.

[642] As noted *infra,* this is one of the pricing reforms that will be available for a defined transition period during which RTOs are being established.

[643] We note that a PBR system that uses a variant of price cap regulation of the National Grid Company has been in use for nine years in England and Wales. More recently, the price cap has been combined with a separate incentive mechanism that focused on reducing congestion on the grid. Since this is the longest-running PBR targeted to grid operations, we encourage any RTO that intends to propose PBR to examine the strengths and weaknesses of the British approach.

measuring them, and determining the effect of sharing such gains on the strength of the incentives faced by the RTO. The Commission does not believe it would be appropriate to specify the exact distribution of such gains, as such a decision is better left to negotiation by all stakeholders.

To the extent possible, the rewards and penalties should be prescribed in advance based on known and measurable benchmarks. PBR designs involve an inevitable trade-off between simplicity and administrative ease on the one hand, and the potential benefits of the program. Although relatively simple designs such as rate freezes provide significant incentives for an RTO to reduce its costs, they produce relatively limited incentives to maintain reliability, promote service quality, or manage congestion. PBR mechanisms that benchmark an RTO's performance, either to its own historical performance, to industry performance indices, to some normative goal, or to a combination of these, may be designed to provide incentives for more efficient operation and investment decisionmaking. The Commission recognizes that designing sophisticated PBR mechanisms will be a significant challenge for RTOs already grappling with other development issues. The Commission, therefore, will make its staff available through our pre-filing process to work with RTOs to help identify and resolve issues on an informal basis prior to their filing a PBR proposal.[644]

7. Other RTO Transmission Ratemaking Reforms

The Commission proposed in the NOPR to consider innovative pricing proposals for transmission owners who turn over control of their transmission facilities to an RTO.[645] The types of pricing that the Commission proposed to consider include: a higher ROE on transmission plant; allowing the transmission owner to retain the benefits of cost saving attributable to RTO formation; acceleration of transmission cost recovery in rates; non-traditional valuation of transmission assets such as an estimate of replacement costs for assets purchased at higher than net original cost; and liberalized allowance of levelized or non-levelized rate methods. The Commission proposed that transmission owners meet all of the requirements to become an RTO before an innovative pricing proposal is accepted.[646]

Comments. A large number of commenters addressed the Commission's proposals to consider transmission pricing reforms for RTOs. About 30 commenters expressed support, and about 30 commenters expressed opposition. There were also a number of comments which did not explicitly support or oppose this aspect of the NOPR.

Supporting Innovative Pricing.[647] Of the commenters that support innovative pricing, a common theme is that if RTO formation is to be voluntary, incentives are required to encourage participation.[648] For example, Justice Department recommends that the positive and negative incentives be designed to secure universal compliance rather than have some utilities not participate because the advantage of continuing outside of the RTO is greater than the incentive to join. EEI supports incentives since RTO formation will probably not generate increased earnings for transmission owners since most of the efficiencies will be a benefit to others. EEI suggests that an application for RTO formation and incentives should include some assessment of the benefits from which the incentives are generated but a precise calculation of benefits should not be required because of the extreme difficulty in making such an estimate. PacifiCorp is in favor of incentives but is concerned that a ''case by case'' consideration of incentives may jeopardize their realization because customers will call for lower transmission rates in the short term once the RTO has been formed. PacifiCorp argues that a more detailed uniform policy on incentives ''up front'' is preferred.

On the other hand, several commenters suggest that the Commission should consider incentives only on a case-by-case basis. Desert STAR says that different RTOs may need different sets of incentives as will public power transmission owners. MidAmerican supports case-by-case consideration of incentives to join an RTO, and favors a higher ROE reflecting the fact that transmission is not limited to selling to a captive customer base in a bundled context but is serving a wholesale marketplace at greater risk. Duke is in favor of incentives for transmission expansion, but cautions that incentives should not bias investment and other decisions, should be considered on a case-by-case basis, and may not be very effective where operation is separated from ownership. Oregon Office is in favor of incentives for meeting all of the RTO characteristics and functions faster than the industry average, but not for average speed in accomplishing RTO formation.

A number of commenters favor offering incentives to public utilities that are already members of an ISO as well as to provide incentives for public utilities to join an RTO. For example, PJM says that incentive rates should be offered to new and existing RTO members to reflect the benefits generated and to prevent inefficient consequences such as transmission owners moving from an existing ISO to a new RTO to receive incentive rates. PSE&G favors a correspondingly higher ROE and faster depreciation of transmission assets for transmission owners who participate in RTOs, including those who have already joined an existing organization. LG&E says that incentive plans can be useful in promoting RTO participation and that existing members of RTOs should be allowed to propose incentive rates as well. LG&E stresses that it is just as important not to enact policies on rates that might jeopardize revenue requirement recovery and thus act as a disincentive. An additional consideration is offered by PP&L Companies which argues that existing participants in RTOs should be allowed the same incentive rates as those which are just forming because the benefits of an existing RTO are greater than those of a start-up RTO not yet in operation.

The proposed incentive addressed most frequently by commenters is allowing a higher rate of return on transmission assets. Georgia Transmission believes that higher ROEs as an incentive to voluntarily join an RTO is appropriate because of the benefits that participation would bring. NSP and others argue that ROE must be sufficient to attract capital and compensate utilities for the risks involved. Conectiv and EEI argue that the current rate of return policy should be modified, arguing that the DCF method gives results that are too low to provide adequate returns to transmission owners causing a reduction in building at a time when more transmission is critically needed. According to Conectiv, the DCF method should be abandoned or its application

[644] Alternatively, the RTO could seek guidance in a more formal proceeding, *e.g.,* if an RTO files a petition for a declaratory order seeking approval of its PBR proposal.

[645] FERC Stats. and Regs. ¶ 32,541 at 33,755.

[646] *Id.* at 33,756.

[647] While we used the term incentive pricing in the NOPR, this term is an imprecise description of the various transmission pricing reforms that will be addressed in this Rule, and we now describe these pricing reforms as innovative rate proposals. However, the comments sections that follow continue to use the term incentive because the parties used this term in their comments.

[648] *See, e.g.,* Avista, TEP, Duquesne, APS, NEPCO *et al.,* Florida Power Corp.

should be modified to account for the current industry situation and be more reflective of conditions in the general economy and reflect reasonable transmission asset lives. Cinergy, in reply comments contends that the record in this proceeding is sufficient to establish a presumption of reasonableness for higher ROEs.

SoCal Edison does not believe that pure incentives in the form of ROE ''awards'' are necessary for encouraging participation in RTO but it does argue that higher returns may be justified on transmission assets controlled by an RTO because the original owner no longer has control over planning and expansion decisions. In addition, distributed generation and bypass may be found to increase risk. SoCal Edison says that it is very important to prevent the move to RTO control from being a financial loss due to Commission rate setting or because of greater risk and higher costs. SoCal Edison does agree with the proposal to allow accelerated depreciation of transmission assets to encourage participation.

TXU Electric is in favor of consideration of higher ROEs for RTO participants and thinks it is more important to take a more global look at transmission ROEs in a new and uncertain industry environment where transmission investment is important. TXU Electric warns that it would be inappropriate to penalize RTO participation with reduced earning potential because unbundled transmission ROEs are lower than ROEs allowed in bundled rates. Conlon suggests that the Commission could allow a higher return on assets of a transco or ISO to serve as an incentive for IOUs to transfer ownership. Southern Company explains that there are major tax consequences to the sale of transmission assets to form a transco and recommends that the Commission find ways to accommodate such a transition. As to rate incentives, Southern Company advocates a change in the Commission's ratemaking policy in order to increase returns to be more commensurate with non-regulated businesses. Southern claims that recent court rulings support higher returns on transmission service.

A number of commenters argue that participation in an RTO increases financial risk, and that incentives are therefore required to encourage RTO participation. For example, Empire District says that turning over control of transmission assets to an RTO increases the risk because someone else will control their operation, justifying higher ROEs for participation. PSE&G argues that a stand-alone transmission company or an RTO is more risky than an integrated electric utility where transmission was a strategic asset. FirstEnergy justifies higher ROEs by noting a number of sources of risk, including emergence of distributed generation, vulnerability of firms that are less diversified than integrated utilities, and quicker phase out of older generation plants which may result in stranding some transmission plants. Midwest ISO argues that RTO membership may cause a loss in earnings due to reduced transmission revenues, higher costs, and operational risks. United Illuminating believes that risk for transmission investment is higher for assets controlled by an RTO and that accelerated depreciation is warranted because transmission companies can no longer count on captive customers, and industry changes have the possibility to abandon transmission plant before its physical life is over. WPSC is in favor of higher ROEs for transmission owners who join RTOs but not as a pure incentive. WPSC's justification for higher ROEs would be the greater risk due to removal of pancaked rates, new generation options, loss of higher state returns, and new technologies. WPSC supports the other rate incentives as long as the benefits exceed the costs based on careful examination.

Some commenters address the broad range of proposed incentives. For example:

- Trans-Elect argues in favor of incentives to include: acquisition premiums, hypothetical capital structures, higher ROE, accelerated recovery of costs, rate moratoriums, and expedited FPA section 205 and 203 approvals. Trans-Elect would limit incentives to those that do not harm transmission customers. It notes that PBRs would allow transmission owners to share in cost savings but some operating history may be needed before they are put in place. It argues that acquisition premiums may assist in the formation of independent transcos, and suggests that if there is a rate moratorium in place, RTOs should be allowed to recover acquisition premiums after the moratorium.
- FirstEnergy advocates flow through of cost savings to owners, non-traditional valuation of assets, flexibility in the use of levelized rate methodology, retention of hourly non-firm revenues, deference to management in dispute resolution, elimination of codes of conduct where there is structural separation, and simplification of filing requirements. Some of these measures should be offered on a limited basis to RTOs not yet meeting all of the characteristics and functions. Incentive plans should weigh costs versus benefits. Cal DWR goes further, saying that incentives should not be allowed until benefits are actually proven.
- Los Angeles recommends that the Commission consider several options for the valuation of assets transferred to an RTO in order to reflect the true value of the assets to native load customers. Selected options to explore include: an up-front acquisition premium used to moderate rates to native load customers, provide native load customers a congestion premium, or grant native load customers an exemption to congestion charges.
- NYPP is in favor of sufficient ROE to provide for expansion and accelerated depreciation to compensate for increased risks as opposed to a ''bonus'' type incentive to join an RTO. Its members contend that this type of incentive should be available to all transmission owners, not just the ones who meet the NOPR's characteristics and functions.

A number of commenters note that incentives are needed to facilitate efficient expansion of transmission assets.[649] Transmission ISO Participants view the incentive needed to induce new transmission construction as more important than incentives to encourage RTO formation. IPCF suggests that FERC should offer transmission owners incentives to expand their networks without meeting all of the requirements of becoming an RTO in order to reverse the trend against building caused by Order No. 888. Williams says that decisions to expand transmission facilities must be made by for-profit entities, must be driven by economic considerations, and the returns allowed must be commensurate with the greater risks today, Williams cautions that returns for RTO participants certainly should not be at a rate that results in a penalty.

Opposing Innovative Pricing. Many commenters oppose the use of incentives for many different reasons. One common theme is that incentives are inappropriate because RTO participation should be mandatory.[650] PJM/NEPOOL Customers argues that the Commission should mandate RTO formation because of the transmission owners' duty to operate in an efficient manner, and because transmission customers will likely pay the costs of the incentives. Ohio Commission

[649] *See, e.g.,* AEP, United Illuminating, PP&L Companies, NU, Otter Tail, NYPP, FirstEnergy, Transmission ISO Participants, Allegheny and Salomon Smith Barney.

[650] PJM/NEPOOL Customers, Lincoln, TDU Systems, APPA, WEPCO.

prefers mandatory participation and questions whether the proposed incentives will be effective. If incentives are used, Ohio Commission recommends that the Commission consider evaluating which incentives will be effective, balancing incentives with disincentives, and recognize regional differences especially in arriving at a solution for the Midwest.

Another common theme is that the costs of incentives may well outweigh the benefits of RTO participation. Illinois Commission argues that if the Commission finds that there are benefits in RTO creation, they should be mandatory. According to Illinois Commission, the examples of incentives proposed in the NOPR, *i.e.*, ROE enhancement, revaluation of transmission facilities at replacement cost, accelerated depreciation, and flexibility in use of levelized cost, would consist of money transfers to transmission owners without contributing to cost control or efficiency. South Carolina Authority is opposed to incentives or disincentives to promote RTO participation unless a factual determination is made that they are absolutely necessary. Similarly, RECA is generally opposed to incentives but would recommend their consideration if savings to the public are well established. RECA finds the rate freeze proposal the least objectionable.

APPA advocates mandatory participation in RTOs and strongly objects to the use of incentives to achieve participation. It argues incentives would be ineffective because of the small proportion that Commission-regulated transmission makes up of the total utility revenue compared to the value of transmission in maximizing generation and merchant revenue. To be effective, APPA argues that the cost would be so large that it would not be offset by the benefits of the RTO. Also, APPA raises the participation issue of whether to give incentives to existing ISO members. Seattle warns against transmission owners ''dumping'' transmission facilities into an RTO to receive incentives when those particular facilities are of no benefit to the RTO being formed.

Some commenters argue that it is inappropriate for the Commission to provide incentives for the provision of a monopoly service. Metropolitan argues that incentives should not be offered because many of the customers who pay for the incentives are the same customers who paid for the original transmission facilities. TDU Systems argues that ROEs for transmission service in an RTO is less risky because of the concentration of monopoly business and the lack of any regulatory gap since all transmission under an RTO will be regulated by the Commission. TDU Systems notes that transmission entities, since they are monopolies, should not earn the same return as firms in other industries. TDU Systems argues that other NOPR proposals, including rate freezes, accelerated recovery of costs and investment, and revaluation of assets, are also an inappropriate enrichment of transmission owners and are unneeded to attract investors. And TDU Systems argues that the proposal for an acquisition premium is troublesome because customers have already been paying for these assets for years. TDU Systems also suggests it will be difficult to calculate what level of incentives would be required to persuade a transmission owner to participate in an RTO and the likelihood of offering a greater incentive than is needed.

Some commenters suggest that providing incentives would violate the Commission's statutory requirement to set rates at just and reasonable levels. NRECA believes that transmission owners should not be rewarded for unjust conduct with incentives and that the Commission should rely on standard cost-of-service based rates. TAPS, which favors mandatory RTO formation, argues that incentives are unnecessary and could nullify the benefits of electric industry restructuring. TAPS argues that incentive rates, including each of the examples suggested in the NOPR, would violate FPA's requirement for just and reasonable rates because they do not reflect the cost of providing transmission service. TAPS does recommend that the Commission remedy unintended disincentives such as utilities' fear of the unknown. UAMPS also favors mandatory participation, and argues that incentives would unfairly raise transmission costs to the benefit of monopoly transmission owners. UAMPS also argues that it is not feasible to divide the benefit of RTO participation before these benefits are even known. In response to the comments of several IOUs, UAMPS argues that the claim that stand-alone transmission companies are more risky is unsubstantiated and should be heard in another proceeding. NASUCA argues that EEI and others are incorrect in saying that the DCF method does not produce reasonable results. According to NASUCA, the DCF method takes explicit account of the transmission owners' risk and the realities of the current regulatory climate.

Some commenters suggest that incentives will not necessarily increase RTO participation, or will not necessarily produce the benefits which the NOPR describes. For example, ICUA notes that incentives cannot be relied upon to achieve participation by all necessary utilities. WPPI opposes incentives to participate in RTOs citing the RTO activity that has already taken place without incentives and the contention that the Commission should designate boundaries and require participation within one year.

Wyoming Commission does not agree that increasing the ROE will be sufficient to encourage more transmission building. According to Wyoming Commission, low building activity may be attributable to difficulty in meeting siting requirements, uncertainty related to retail access and native load, and competition for more localized generation. Wyoming Commission does not think that the Commission should rush too quickly into some innovative ratemaking before the industry has committed to making RTOs work as planned. And the Wyoming Commission suggests that a higher ROE for transmission investment may discourage a balanced consideration of options.

A number of commenters generally opposed incentives, believing that sanctions or penalties against public utilities which do not join RTOs is superior to providing incentives. NASUCA argues that mandates or disincentives for not joining at the time of merger or market-based rate requests should be used rather than incentives. Incentives would not be cost based and would therefore make rates unjust and unreasonable. As to specific incentive proposals, NASUCA says that using replacement cost for transferred assets would allow higher rates than necessary as an incentive and would charge customers for assets they have already paid for. Such incentives could set off a transmission sell-off in anticipation of an adjustment and some companies may refuse to form transcos until they were granted the same adjustment as any other company. NASUCA is opposed to accelerated depreciation of assets for similar reasons. NASUCA also states that incentive rates could harm electric competition by increasing transmission costs. And Big Rivers states that the incentives proposed in the NOPR are inappropriate for rural electric cooperatives.

Other Comments. A few commenters did not take an explicit position on the use of incentives, but made general comments on the Commission's proposals. For example:

- Cal ISO is more concerned that there not be disincentives to RTO participation than offering incentives. In particular, Cal ISO points out the disincentive created by the Commission's annual fee policy, from which temporary relief was granted [651] but a permanent solution is needed.

- New Century recommends against the use of ''remedial measures'' to encourage participation such as the suspension of market-based rate authority, denial of merger authority, and denial of non-pancaked rate access to RTO facilities.
- Entergy says that the NOPR's statements on incentives are vague and would cause too much regulatory uncertainty. Entergy asks the Commission to provide more explicit provisions as to what incentives would be approved.
- Canada DNR is concerned that Canadian transmission owners not be placed at a disadvantage for non-participation in an RTO in terms of incentives and disincentive.
- SRP supports incentives as long as they are applied to both public power entities and investor owned companies equitably.
- Metropolitan contends that it would not receive much benefit from any incentives offered to RTOs because it is a public entity and because its asset base is so heavily depreciated. However, replacement cost methodology could be of use in mitigating cost shifts from rolling in higher costs of other utilities.

Commission Conclusion. As noted earlier, the NOPR and the comments use the term incentive pricing as a label for the transmission pricing reforms that we raised for discussion. Certainly, good pricing affects behavior. But good pricing also achieves a valuable goal, in terms of competition, system expansion, or efficient practices that benefit more than the transmission owners or the RTO. In this section we provide greater specificity with respect to certain transmission pricing mechanisms that may be appropriate for RTOs. These mechanisms were described in the NOPR or otherwise proposed by commenters, and are included in the amended regulatory text.[652] We emphasize that we do not intend this policy guidance to be interpreted as a Commission regulatory requirement for a specific transmission pricing method, nor should it be interpreted as a guarantee that the Commission will approve any particular innovative pricing proposal. We emphasize that all innovative pricing proposals filed by RTOs must be fully and adequately supported in accordance with this Final Rule and the regulatory text. We believe that we are providing sufficient guidance for RTOs to make critical decisions with respect to transmission pricing policies. If industry participants believe that further guidance from the Commission is needed to resolve transmission pricing issues, they may request such guidance through requests for declaratory orders or further rulemakings.

As discussed earlier, transmission pricing reform is needed as a result of the rapid restructuring of the industry that is underway, particularly with respect to changes in the ownership and control of transmission assets, and changes in the transmission services being provided in competitive generating markets. As a result of these changes, and consistent with a number of commenters' arguments, we have concluded that the Commission, at a minimum, needs to mitigate various ''disincentives'' that may prevent transmission owners from efficiently operating their systems. Commenters cite to the potential that transmission owners will earn lower returns for providing unbundled transmission service than they earned for providing bundled service, even though risks associated with transmission ownership have increased. Commenters suggest a number of sources of increased risk. One source is the potential for bypass of transmission assets due to distributed generation and the phasing out of older generators from service. Other sources are directly related to RTO formation. For example, some commenters assert that stand-alone transmission companies (*e.g.*, transcos) are riskier because they have a less-diversified portfolio of assets than a vertically integrated utility. Other commenters argue that participation in an RTO that is an ISO is inherently riskier, suggesting that increased risk comes from ownership of transmission assets that are ceded for purposes of operational control to another, non-affiliated entity.

Other commenters argue that a reevaluation of transmission pricing is needed because it is absolutely critical that the transmission grid support competitive generating markets, and the only way that the Commission can ensure this will happen is to pursue pricing policies that encourage it. Some commenters suggest that because the contribution of transmission to total costs of energy is relatively small[653] overinvestment in transmission will not significantly affect delivered electricity prices. Further, the Commission should be much more concerned about underinvestment, not overinvestment, in the transmission grid.[654] Stated another way, an efficient transmission grid is a prerequisite to achieving competitive generating markets, and the potential benefits for consumers far exceed any limited overinvestment that may occur on transmission service. A related argument is that efficiency benefits of improved transmission service will be captured by producers and customers of generation, not transmission providers; therefore, greater incentives for RTOs to provide good transmission operations and efficient investments in the grid are warranted.

The NOPR sought comments on several procedural issues related to transmission pricing reform and incentives. One issue was whether these pricing reforms should be available to participants of existing ISOs, or be available only to transmission owners that join RTOs as a result of the Commission's RTO initiative. We have concluded that members of an existing ISO organization that satisfy the minimum RTO requirements in the regulatory text should be allowed to seek transmission pricing reform as newly formed RTOs, so that they can avail themselves of the same incentives for efficient operation of and investment in the transmission grid. Furthermore, we believe that the Commission's approach to evaluating innovative transmission reforms should be neutral with respect to the organizational structure of the Applicant, so that RTOs that own transmission assets as well as RTOs that do not own transmission assets would be equally eligible for such ratemaking treatments.

Another issue is whether the Commission would prescribe which transmission pricing reforms it would accept and which it would not accept, or whether the Commission would consider such proposals on a case-by-case basis. We conclude that a case-by-case evaluation of transmission pricing

[651] PJM Interconnection L.L.C., 88 FERC ¶61,109 (1999).

[652] Note that these mechanisms are discussed below on a thematic basis, although the regulatory text lists them on an individual basis.

[653] For example, Salomon Smith Barney, citing to an article by Leonard Hyman notes that the direct, total osts of transmission service represents about six to seven percent of the average customer's bill, and raising transmission prices even as high as 25 percent in order to attract capital adds only two percent to the overall electric bill.

[254] Professor Joskow points out that the external factors, such as licensing requirements, the need for rights of way, and NIMBY (*i.e.*, ''not in my backyard'') opposition to transmission expansion already places significant constraints on overinvestment in major new transmission projects.

reform proposals is appropriate, given that such proposals are not generic in nature, and a proposal may be appropriate in some RTO circumstances but not in others. However, the Commission believes some further specificity on transmission pricing reform is warranted to provide industry participants with the Commission's evolving views, as RTOs consider the appropriateness of various reform measures.

Therefore, we provide greater specificity on three transmission pricing reform measures: (1) ROE; (2) levelized rates; and (3) accelerated depreciation and incremental pricing for new transmission investments. We note that some of these measures may be useful only as transitional devices that may be necessary to spur the prompt creation of RTOs and, therefore, we intend to offer these pricing options only for a defined period of time, as detailed later in this Final Rule. On the other hand, other pricing reforms may be useful as permanent features, and will not be limited only to the period during which RTOs are forming. Finally, while certain of these innovative pricing proposals may be more helpful to one RTO structure than another (*e.g.*, ISO vs transco), we do not believe that any of these pricing proposals would be incompatible with any particular structure adopted by RTOs.

a. Return on Equity (ROE). More commenters focused on ROE-based proposals than any other type of transmission pricing reform. These commenters make two main points. One argument is that higher ROEs will be demanded by the market as a matter of course as the industry restructures and the risk of transmission business increases, and the Commission must allow higher ROE to reflect participation in RTOs. A second argument is that joining an RTO adds another level of risk that warrants a specific adjustment to ROE (*e.g.*, going to the high end in the range of reasonable ROE, or a specific basis point adjustment).[655]

As discussed above, commenters urge the Commission to provide flexibility in allowing ROE-based programs for RTOs. Many of these commenters specifically urge the Commission to ensure that there are sufficient incentives for an RTO to make needed investments in transmission infrastructure. On the other hand, a number of commenters oppose ROE-based programs on the grounds that they constitute a ''bribe'' for utilities to provide service that they are statutorily required to provide.

We believe that there are a number of issues surrounding ROE that must be addressed by the Commission. For example, we believe that allowing an RTO to propose a formula rate for determining return on equity is consistent with our view that risks and rewards for transmission owners should reflect market-like forces to the extent possible. Allowing a formula rate of return would decouple a transmission owner's earnings from its own equity valuation, and would tie it more to external standards such as industry-wide performance. Such an approach is also consistent with the benchmarking that may occur under PBR.

We also agree that the risk profile of the transmission business is changing as the industry restructures, and that it may vary as a function of the structure each transmission company elects. For example, the risk associated with owning facilities that are leased for a sum certain to another entity operating an RTO may be different from the risk associated with operating a stand-alone transco that is facing a significant expansion program. We therefore conclude that ROE-based initiatives—as well as other ratemaking reforms discussed below—may be applicable to all types of RTOs, without regard to organizational structure.

We further recognize that historical data typically used to evaluate ROEs may not be reliable since it reflects a different industry structure from the one that exists recently. And we believe that as patterns of transmission ownership and control evolve, new approaches to compensating transmission owners for different capital structure mixes may be warranted, including allowing a transmission owner to seek a return on invested capital, independent of its exact capital mix.[656] As noted above, we are willing to consider moratoriums tied to the rates the transmission provider earns on transmission assets with respect to bundled retail power sales, and the moratorium option may be tied to the existing transmission rate level, or to the existing return on equity.[657]

Finally, we agree that the uncertainty associated with the transition of the industry, and in particular participation in RTOs, may increase risks in the short-run. Certainly, our goals have not changed, which are to ensure that customers have access to nondiscriminatory service at just and reasonable rates, and that transmission owners have an opportunity to earn a reasonable rate of return on their investment. We recognize that in this era of rapid change, new approaches to setting ROE may be needed to implement that standard. We therefore invite RTOs to submit proposals for ROE-based programs that are in conformance with these new approaches.

We note that pricing reforms involving ROE would clearly be compatible with all types of RTO structures that involve a determination of return on equity on transmission rate base, *e.g.*, transcos, ISOs, or tiered organizational structures.

b. Levelized Rates. A number of commenters argue that the Commission should allow RTOs to adopt levelized rates. A levelized rate is designed to recover all capital costs through a uniform, nonvarying payment over the life of the asset, just as a traditional home mortgage payment does. The Commission, has held in a number of recent proceedings that both levelized and nonlevelized rates can produce reasonable results, depending on the circumstances.[658] The Commission stated in these cases that where a utility proposes to switch from a nonlevelized net plant rate design method, ''[i]n supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method.'' [659]

The Commission believes that levelized rates are preferable in an RTO environment because all customers, regardless of when they take service, face the same price. Also, given a depreciated investment base, levelized rates based on existing investments will be higher than non-levelized rates and will address concerns that RTO formation will decrease revenues.

The principal objection to allowing levelized rates for RTOs is that it may raise RTO transmission rates in the short-run. The Commission has been reluctant outside the RTO context to approve switches from or to levelized rates proposed by public utilities under traditional cost-of-service ratemaking because of the opportunities that switching may provide for utilities to

[655] Some commenters recommend abandoning the DCF method of calculating ROE entirely. We are not adopting that recommendation.

[656] As noted *infra*, this is one of the pricing reforms that will be available only for a defined transition period during which RTOs are being established.

[657] As noted *infra*, moratoriums are among the pricing reforms that will be available for a defined transition period during which TROs are being established.

[658] *See, e.g.,* American Electric Power Service Corp., Opinion 440, 88 FERC ¶ 61,141 at 61,441–42 (1999) (*AEP*); Allegheny Power Service Corp., Opinion 433, 85 FERC ¶ 61,275 at 62,117 (1998); Kentucky Utilities Co., Opinion 432, 85 FERC ¶ 61,274 at 62,100–03 (1998) (*KU*).

[659] *See AEP,* 88 FERC at 61,441–42.

over recover transmission costs. However, consistent with our discussion above of how market restructuring may require innovation in transmission pricing, we believe that levelized rates may be appropriate in circumstances, as here, where an RTO reflects a fresh start with respect to the provision of transmission services, and potentially the customers for those services. This is especially true in cases where RTO formation occurs coincident with market restructuring, such that the transmission customers of the RTO may be significantly different than the traditional, captive customers, that formerly took transmission service. We therefore conclude that the Commission should allow increased flexibility for RTO proposals that include ratemaking practices based on levelized rates. Clearly, this pricing reform, which relates to the method used to compute the transmission revenue requirement in the first instance, is compatible with any type of RTO structure, e.g., transco, ISO, or tiered structure.

c. Accelerated Depreciation and Incremental Pricing for New Transmission Investments. While a number of commenters have suggested accelerated depreciation as a transmission pricing reform that should be considered, these arguments are premised on the possibility that transmission costs will be stranded by changes in the industry, such as bypass of portions of the transmission system. We think that these concerns are speculative at this point in the industry's restructuring. For example, we are not convinced that the problem of stranded transmission assets is anywhere near the level of concern that stranded generating assets represents.[660] In any event, should certain limited transmission facilities become stranded, nothing prevents proposals to recover prudent costs under traditional ratemaking policies.

We will, however, make a distinction between accelerated depreciation for existing transmission assets, and accelerated depreciation for new transmission facilities. While we will not bar proposals of this type for existing assets, we cannot give any encouragement to them in the Final Rule. On the other hand, we believe that it is appropriate for the Commission to provide those willing to make new transmission investments with the flexibility to propose that such assets follow non-traditional depreciation schedules. The purpose of providing such flexibility is to remove disincentives for the construction of new facilities. We think such flexibility is warranted because the fundamental nature of transmission investment may be changing with respect to the entities that will make investments in the transmission system in the future and who pays for the new transmission facilities. Furthermore, given the rapid changes in market structure and dynamics that have occurred and will likely continue, we are not certain that traditional determinations of the economic life of new transmission facilities remain appropriate.

In addition, we believe it is appropriate for the Commission to provide flexibility for pricing of new facilities, such that proposals for pricing of new facilities that combine elements of incremental prices with embedded-cost access fees will be considered. Although we are concerned that such ratemaking practices have the potential to lead to higher prices for new transmission services, and also potential to lead to overinvestment in transmission facilities, e.g., where generation redispatch could accomplish the same objective at lower cost, we believe that such practices, if carefully constructed, will create appropriate incentives for efficient investment in new transmission facilities. We also believe that this pricing reform will be attractive to all types of RTO structure, e.g., transcos, ISOs, or tiered structures. It may also be used by any RTO that chooses to rely on third parties to construct new facilities.

d. Acquisition Adjustments. A number of commenters suggest that the Commission adopt new policies for acquisition adjustments that would provide assurances to purchasers of transmission facilities that acquisition premiums would be recoverable through transmission rates. We do not adopt this suggestion in this Final Rule.[661]

8. Additional Ratemaking Issues

A number of comments on ratemaking issues address topics not specifically enumerated in the NOPR.

Comments

- Williams, CSU, Alliance Companies and WPSC encourage the Commission to consider rate designs based on mileage or network usage.
- Great River, NCPA and IMPA raise the concern that cooperatives and public power entities need assurance that they will receive full customer credit and compensation as was explicitly stated in Order No. 888. SoCal Edison claims that full compensation will be forthcoming and will not be a problem.
- Ohio Commission recommends that a tariff for border transactions (between RTOs) be implemented that makes the market over the combined regions seamless to persuade some regional organizations to combine.
- PPC notes that IndeGO ran into a problem with developing rates for combined systems with very different levels of quality and cost, and that systems at a position of lower quality should be required to meet combined system standards at their own cost.
- Puget argues that RTO rates must provide for the collection of stranded costs.
- PSNM sees a problem with load-side generation customers who do not have to pay their fair share of total system transmission costs.
- Powerex objects to the proposal to segment companies' service areas into sub-zones for pricing purposes.
- Alliance Companies and AEP favor the flexibility in RTO rate filings that would allow companies to make proposals that reflect market forces.
- Alliant Energy is concerned that RTO structures promote workable markets and that transmission rates be permitted to include a fair accounting of RTO start-up costs.
- East Texas Cooperatives recommends that RTO pricing structures adequately compensate small transmission owners who join the RTO, creating an incentive to join and be a more equitable system.
- Georgia Transmission says that ratemaking for RUS borrowers must take into account the requirements of any RUS loans. In addition, Georgia Transmission recommends that the cost of RTO formation be allowed in RTO rates.
- Metropolitan, Cal DWR, and SoCal Cities favor the use of time-of-use pricing or off-peak rates for transmission.
- Oregon Office recommends load-based fees for transmission rather than volume based charges.
- IMEA argues that the RTO start-up and administrative costs should be

[660] *See* Order No. 888, wherein the Commission allows recovery of stranded costs (primarily generation related) only when they are unrecoverable from customers that depart the system, and only upon a definitive showing that the utility had a reasonable expectation of continuing to serve the customer after the customer's departure.

[661] *See* Minnesota Power & Light Company and Northern States Power Company, 43 FERC ¶ 61,104 at 61,342 (1988), for a discussion of the Commission's existing policies with respect to the ratemaking treatment for acquisition premiums. *See also* Duke Energy Moss Landing LLC, *et al.* 83 FERC ¶ 61,318 (1998).

allocated to all customers including bundled native retail load. In contrast, LG&E notes that if native load is assigned RTO administrative costs there may be under recovery because of retail rate freezes.

- Industrial Customers argue that assets used for remote generation should be excluded from the RTO.
- Merrill Energy says that the incremental pricing of new transmission upgrades prevents expansion because customers are unwilling to pay.
- NERC is concerned about the recovery of costs related to reliability-related generators.
- NRECA is concerned about compensation by an RTO for low-use transmission facilities owned by cooperatives, because large transmission owners are opposed to revenue sharing. NRECA notes that if a cooperative joins an RTO, transactions for all will increase and there is more to share. Also, there should be protection for joint use agreement income.
- Project Groups says that pricing must facilitate entry and usage by efficient, environmentally benign resources. Grid access barriers to these resources need to be eliminated. NMA/WFA/CEED respond by saying that the policies that Project Group objects to are equitable overall.
- Seattle argues that hub and spoke pricing should be used and discrete inter-regional tariffs are needed.
- NWCC notes that the characteristics of wind-produced power presents problems fitting into an RTO pricing arrangement and says that wind power works best with energy-based pricing systems.
- Detroit Edison advocates a two-part pricing structure similar to that proposed by the Alliance RTO. It includes a local rate and a regional rate. To encourage participation, Detroit Edison proposes that the Commission allow RTOs to develop market-based transmission pricing methodologies.

Commission Conclusion. Commenters raise a number of important ratemaking issues that must be considered in the establishment of RTOs. We clarify that the reasonable costs of developing an RTO may be included in transmission rates. Other issues are at a level of detail and specificity that we do not believe should be resolved in this Final Rule. Therefore, these issues will be considered as they apply to individual RTO proposals on a case-by-case basis.

9. Filing Procedures for Innovative Rate Proposals

We shall evaluate all RTO proposals including any innovative rate treatment based on the applicant's demonstration of how the proposed rate treatment would help achieve the goals of regional transmission organizations, including efficient use of and investment in the transmission system and reliability benefits. We shall also require applicants to provide a cost-benefit analysis, including rate impacts, and demonstrate that the proposed rate treatment is appropriate for the proposed RTO and that the rate proposal is just, reasonable, and not unduly discriminatory.

In addition, pricing proposals involving moratoriums and returns on equity that do not vary according to capital structure may not be included in RTO rates after January 1, 2005. Thus, if the Commission approves an RTO rate proposal involving, *e.g.,* a rate moratorium, unless otherwise ordered, the moratorium would end on or before January 1, 2005. We are limiting these rate proposals for a defined period during the formative stage of RTOs because, while either may be appropriate as transitional rate mechanisms, they do not promote long-term efficiency through rate design. In addition, the limited duration for these rate treatments will encourage the earliest possible filings, while at the same time giving some flexibility to those filings that may be delayed.

H. Other Issues

1. Public Power and Cooperative Participation in RTOs

In the NOPR, the Commission stated its objective of encouraging all transmission owning entities including transmission owned or controlled by public power entities and cooperatives, including Federal Power Marketing Agencies (PMAs), Tennessee Valley Authority (TVA), and other state and local entities to place their transmission facilities under the control of an RTO.[662] To this end, we expressed an expectation that public power entities would fully participate in the collaborative process for forming RTOs.[663] In addition, we noted that some public power entities filed open access tariffs with the Commission and others are participating in ISOs and other regional institutions. The Commission, however, is aware and concerned that public power entities face several difficult issues regarding RTO formation and participation.[664]

The first issue is the Internal Revenue Service (IRS) Code ''private use'' restrictions on the transmission facilities of public power entities financed by tax-exempt bonds. We noted that IRS temporary regulations may allow facilities financed by outstanding tax-exempt bonds to be used to wheel power in accordance with Order No. 888, but that these temporary regulations may not allow the issuance of additional tax-exempt bonds for expanded transmission or permit transfer of operational control of existing transmission facilities financed by tax-exempt bonds to a for-profit transco.[665] The Commission asked for comments on the extent to which IRS Code restrictions may limit the transfer of operational control or other forms of control, or ownership of public power transmission facilities to a for-profit transco or other forms of an RTO.

The Commission also requested comments on state and local charter limitations, prohibitions on participating in stock-owning entities, the current policies of various local regulatory entities that affect or impede full public power participation in RTOs and legal restrictions or other considerations regarding PMAs that prevent their participation in RTOs. We questioned whether the Commission should consider some forms of associate membership or participation and other special accommodations in order for public power entities to overcome obstacles to RTO participation.[666]

Comments. Most commenters support the Commission's position that a properly formed RTO should include all transmission owners, including cooperatives and public power, in a specific region.[667] As EEI notes, public power participation will enhance the reliability and economic benefits of an RTO. Furthermore, some commenters argue that in some areas of the country, especially in the Northwest and Southeast, RTO formation may be impractical without public power participation.[668] Virtually all commenters recognize that regulatory and legal restrictions exist that may impede public power and cooperative participation in RTOs. EEI, SERC and Metropolitan argue that the best way to

[662] FERC Stats. and Regs. ¶ 32,541 at 33,756–57.

[663] *Id.* at 33,757.

[664] *See id.*

[665] *Id.*

[666] *See id.*

[667] *See, e.g.,* Oglethorpe, Allegheny, Montana Power, CREDA, Tallahassee, Arkansas Cities, PPC, California Board, Industrial Customers, Entergy, BC Hyrdo, Powerex, Aluminum Companies, MEAG, Arizona Commission, Nevada Commission, East Texas Cooperatives, Lincoln, NPPD, Wyoming Commission, Georgia Transmission, WPSC, PGE, Montana Commission, SMUD, Cal ISO, MLGW, Loveland Customers, NASUCA, Duke, LG&E, CP&L, South Carolina Authority, STDUG, NCPA, PP&L Companies, Desert STAR, PG&E and EEI.

[668] *See, e.g.,* EEI, Snohomish, MLGW, Loveland Customers, Montana Commission, Wyoming Commission, Aluminum Companies, Industrial Customers and Powerex.

facilitate non-jurisdictional utility participation in RTOs is for the Commission to avoid a ''one-size-fits-all approach'' and to provide flexible rules in order to accommodate the unique needs of public power entities.

Section 141 of the IRS code imposes limitations on the use of non-governmental entities of public power facilities financed with tax exempt bonds. These private use limitations restrain the form and extent of participation by public power systems in RTOs. The key private use limitation that is material to RTO participation is a bar on the sale of the output of facilities financed with tax exempt debt to non-governmental entities on terms not available to the general public. Commenters note that in January 1998, the IRS issued temporary regulations relating to the application of the private use rules to public power entities that provide some relief for transmission facilities. These temporary regulations permit issuers of outstanding tax exempt bonds to offer open access transmission services and competitive access to distribution systems, and to join RTOs, provided that certain conditions are met, particularly that the facilities continue to be owned by the municipal entity. The temporary regulations, however, do not provide the same relief to issuers of new tax exempt bonds. Many commenters assert that the temporary regulations will expire in January 2001 and that these regulations are incomplete and not permanent.[669] LPPC notes that the ability of issuers to continue to rely on the temporary regulations after expiration is unclear and therefore, issuers taking actions permitted under the temporary regulations risk having tainted the tax-exempt status of their bonds on the expiration of the regulations.

Commenters offer varying solutions to the ''private use'' restriction problem. Many commenters urge the Commission to actively attempt to influence the IRS and Congress to remove and/or mitigate the tax impediment.[670] SRP also recommends that the Commission require all RTOs to demonstrate that they have made a good faith effort to reduce barriers to participation and to accommodate legal restrictions faced by potential participants. Arkansas Cities proposes a transitional grandfathering of existing tax-exempt bonds. Arkansas Cities notes that such legislation is pending in Congress and is identified as the Bond Fairness and Protection Act (BFPA). Arkansas Cities states ''that if enacted, the BFPA would clarify tax laws and regulations governing tax exempt bonds so that publicly owned utilities would be able to participate in the development of competitive electric utility markets.''[671] Duke asserts that the leasing of transmission facilities to an RTO is a viable option. Moreover, LPPC states that public power entities have to be allowed to participate in a way that permits them to retain sufficient operational control of their transmission systems to stay within the private use limitations. In addition, LPPC, Snohomish, Arkansas Cities and East Texas Cooperatives argue that public power entities need an opt-out provision if their tax exempt status is threatened. TEP recommends that the final rule contain a template for addressing how transactions can be administered if they involve the use of tax exempt facilities. TEP proposes that (1) an RTO should operate in a manner that either preserves the tax exempt status of such facilities or provides compensation to the facilities' owner to the extent it incurs economic harm; and (2) that an RTO should develop specific rules governing the operation and administration of tax-exempted financed facilities.

NRECA details the obstacles confronting cooperatives including the requirement that in order to maintain tax exempt status under Section 501(c)(12) of the IRS Code, at least 85 percent of a cooperative's income must come from the cooperative's members. If such member-derived revenue does not equal at least 85 percent of total revenue, then a cooperative would lose its tax-exempt status. Georgia Transmission argues that there is a real risk that participation in an RTO could result in a cooperative losing its tax exempt status if the revenue received from the RTO (assuming the RTO is not a member of a cooperative) exceeds 15 percent of the cooperative's total income. The revenue received from the RTO would stem from revenue attributed to use of the cooperative's transmission facilities controlled by the RTO.

One remedy to this problem, suggested by AEPCO and Wolverine Cooperative, is to increase an RTO's compensation to the cooperative to include a gross-up of net margins to cover the income tax expense. Under this approach, the RTO would pay the cooperative the full revenue requirement for the transmission facilities, including any other taxes. East Kentucky proposes that a conduit or a pass-through relationship between the RTO and the cooperative would satisfy the IRS restrictions and allow a cooperative to maintain its member-derived character. According to East Kentucky, the RTO would act as an agent for the cooperative by collecting the transmission revenues and holding these revenues in a trust on behalf of the cooperative. Furthermore, Georgia Transmission suggests that the Commission allow a cooperative to leave an RTO if it appears that it may lose its tax exempt status because of the level of RTO and other non-member revenue it expects to receive in a given year.

Another impediment to public power participation in RTOs is mortgage restrictions. AEPCO notes that under the terms of a typical RUS mortgage, either transfer of control of transmission assets to an RTO or a sale, unless authorized by RUS, would be an event of default. East Texas Cooperatives argues that the Commission should require all RTOs to accommodate mortgage restrictions by allowing cooperatives to retain control of their facilities until the mortgage restriction is lifted or a creditor or RUS approves the transfer. In its comments, RUS recognizes that development of RTOs may offer considerable benefits to RUS borrowers, and RUS states that it is exploring means to facilitate borrower participation consistent with the Rural Electrification Act and RUS's fiduciary duties to the U.S. Treasury and taxpayers.

According to several commenters,[672] many public power entities operate under explicit state constitutional restraints with respect to their ability to participate in the ownership of a privately-owned RTO.[673] Further, some state constitutions include restrictions on the use of public funds.[674] Several states, however, expressly authorize public power entities to join with other

[669] *E.g.,* Los Angeles, SoCal Cities, LPPC, APPA, Tacoma, NCPA, SRP, TAPS, EEI, NPPD and East Texas Cooperatives.

[670] *See, e.g.,* EEI, TAPS, SRP, Georgia Transmission, Arkansas Cities, Nevada Commission, PP&L Companies, TANC, Desert STAR, NCPA, Montana-Dakota Enron/APX/Coral Power and Tallahassee.

[671] *See* Reply Comments of Arkansas Cities at 6.

[672] *See, e.g.,* LPPC, NPRB, Snohomish, Clarksdale, MEAG and CAMU.

[673] For example, the Nebraska Constitution provides: ''No city, county, town, precinct, municipality or other sub-division of the state, shall ever become a subscriber to the capital stock, or owner of such stock, or any portion or interest therein of any * * * private corporation or association.''

[674] For example, the Colorado Constitution states: ''Neither the state, nor any county, city, town, or township shall lend or pledge credit or faith thereof, directly or indirectly, in any manner to, or in aid of, any person, company or corporation, public or private, for any amount, or for any purpose whatever; or become responsible for any debt, contract or liability of any person, company or corporation, public or private, in or out of the state.''

public entities in the ownership and operation of electric transmission facilities.[675] In addition, state and local laws impose additional restrictions on the activities and operations of public power entities that could affect the operations of any RTO in which they hold an ownership interest. For example, some laws prohibit the sale or lease of transmission facilities to a for-profit entity.[676]

In states in which laws allow a public utility district to sell or lease its transmission facilities to an RTO, the laws impose requirements on such sale or lease. For instance, Washington law would require the property to be offered in a competitive bidding process, and no sale could occur without voter approval.[677] Furthermore, LPPC notes that state and local laws in California, Florida, Nebraska, and Texas would require the approval of the City Council, the public utility commission, the governing board, or other governmental authority before a transfer of facilities could occur. CAMU and NPPD also state that many municipals and power authorities have statutory authority to condemn property and that it is unlikely that this eminent domain authority can be delegated to an RTO.

Enron/APX/Coral Power notes that an unwillingness to participate in an RTO for commercial reasons should render non-jurisdictional transmission owners ineligible for RTO services and savings. Moreover, Duke argues that public power must take the lead in resolving these issues for themselves. Duke notes that investor-owned utilities have overcome numerous obstacles to become RTO participants. Furthermore, Enron/APX/Coral Power argues that public power and other non-jurisdictional transmission owners that elect to share in the benefits of an RTO must be held to the same characteristics and functions as jurisdictional transmission owners. Cinergy suggests that the Commission commence regional technical conferences to address legal obstacles to public power entities' participation in RTOs and to explore possible alternatives to operational and functional integration of public power systems into RTOs.

Commenters also address issues relating specifically to PMAs. Many commenters support the expansion of the FPA to give the Commission jurisdiction over all transmission owners.[678] CREDA points out that PMAs are restricted by: (1) enabling statutes; (2) congressional appropriations; (3) the inability to grant indemnification without congressional approval; (4) the sovereign immunity doctrine; and (5) their load serving responsibilities. MLGW notes that other PMA restrictions include the TVA ''fence restriction,'' whereby, TVA's organic statute prohibits TVA from performing any transmission service that would result in the delivery of power generated by TVA outside the specified TVA service area. MLGW further notes that existing long-term contracts between TVA and its distributors are another barrier to RTO participation by PMAs. To remedy these problems, TVA and others[679] argue that the Final Rule should provide enough flexibility to ensure that public power obstacles can be addressed and mitigated.

On the issue of whether the Commission should consider special accommodation, commenters disagree over whether the Commission should provide incentives to public power entities in order to make RTO membership financially attractive. EEI and APPA urge the Commission to adopt an RTO policy that makes membership attractive to public power entities in terms of efficiency and benefits.

SoCal Edison is strongly opposed to the Commission providing incentives in the form of uniform grid-wide rates or transmission credits. SoCal Edison argues that these incentives are nothing more than inequitable cost shifts to retail ratepayers. Likewise, Duke argues that public power entities should not be provided with competitive advantages in order to encourage voluntary RTO participation.

In contrast, IMPA and SoCal Cities urge the adoption of a final rule that provides proper credits or compensation for facilities contributed to an RTO, including customer-owned facilities. Furthermore, East Kentucky states that return on equity can be mitigated by allowing cooperatives to earn a rate of return similar to investor-owned utilities. Vernon argues that the entitlement for transmission facilities contributed to the RTO grid and the appropriate level of compensation are matters that should not be determined nationally on a generic basis, but rather, should be decided in the context of each RTO. SRP supports PBRs and other incentives as long as they are applied to both public power entities and investor owned companies equitably. Metropolitan contends that it would not receive much benefit from any ROE incentives offered to RTOs because it is a public entity and because its asset base is so heavily depreciated. However, a replacement cost methodology could be of use in mitigating cost shifts for Metropolitan due to rolling in higher costs of other utilities. Oregon Office recommends that public power entities be eligible for the same incentives as offered others to the extent that the Commission regulates their rates.

A few commenters discuss issues relating to public power and the filing requirements. South Carolina Authority states that any RTO proposal should contain a detailed description of the efforts made by petitioners to accommodate the transmission facilities of publicly owned utilities. Similarly, SRP, APPA and LPPC recommend that the Commission require each RTO proposal to demonstrate: (1) how a good faith effort was made to accommodate public power participants, particularly deciding ownership structure; and (2) where public power entities are not included, why there are no reasonable terms and conditions under which the RTO could accommodate its participation. Lincoln and Cinergy essentially concur.

Commission Conclusion. We reaffirm our preliminary determination that a properly formed RTO should include all transmission owners in a specific region, including municipals, cooperatives, Federal Power Marketing Agencies (PMAs), Tennessee Valley Authority and other state and local entities. As noted by some commenters, public power and cooperative participation in RTOs will enhance the reliability and economic benefits of an RTO. Furthermore, participation by public power entities and cooperatives is vital to ensure that each RTO is appropriate in size and scope.

Virtually all commenters note that public power entities and cooperatives face numerous regulatory and legal obstacles regarding RTO participation. Commenters assert that these obstructions include: (1) IRS ''private use'' restrictions and the temporary regulations enacted to mitigate the ''private use'' restrictions; (2) the

[675] For example, Washington law provides: ''Any two or more [Washington] cities or public utility districts or combinations thereof may form an operating agency * * * for the purpose of acquiring, constructing, operating, and owning plants, systems and other facilities and extensions thereof, for the generation and transmission of electric energy and power.''

[676] Nebraska law provides that: ''[T]he plant, property, or equipment of a public power district shall never * * * by outright sale, or lease, become the property or come under the control of any private person, firm, or corporation engaged in the business of generating, transmitting, or distributing electricity for profit.'' Nebraska Rev. Stat. § 70–646.01.

[677] *See* LPPC at 17.

[678] *See, e.g.,* LG&E, Otter Tail, WPSC, Alabama Commission, Montana Commission, and DOE.

[679] *See, e.g.,* CAMU, CMUA, STDUG, CREDA, NY ISO, Powerex, PP&L Companies, Desert STAR, CP&L, LPPC, MEAG and Tennessee Authority.

requirement that at least 85 percent of a cooperative's income must come from the cooperative's members (IRS Code Section 501(c)(12)); (3) RUS mortgage restrictions; (4) state constitutional restraints; (5) state and local laws; and (6) specific legal restrictions applicable to PMAs. In addition, commenters offer a variety of solutions to mitigate or eliminate these obstacles to public power participation in RTO formation and operation.

We acknowledge that public power entities face several difficult issues regarding RTO participation and we appreciate the potential solutions offered by numerous commenters. At this time, however, we will not analyze each of the specific resolutions proposed by the various commenters. Instead, on an RTO-by-RTO basis, we will examine submitted proposals that provide public power and cooperatives with the flexibility to join an RTO without jeopardizing their tax or mortgage status. We note, however, that the offered solutions must be consistent with the minimum functions and characteristics outlined in the Final Rule.

We are aware that some public power entities and cooperatives have found ways to participate in existing ISOs. For example, we approved the formation of the NY ISO contingent upon a ruling of the Internal Revenue Service that the formation and operation of the NY ISO would not jeopardize the tax-exempt status of the New York Power Authority.[680] Furthermore, we are encouraged by the recent efforts of the Member Systems of the New York Power Pool (NYPP) to include and accommodate the participation of Long Island Power Authority (LIPA) in the NY ISO. NYPP proposed language in their OATT that provides LIPA will not be required to provide transmission service where the provision of such service would result in the loss of its tax-exempt status for its bonds. NYPP also proposed additional scheduling protocols and procedures to ensure the continued tax-exempt status of LIPA. The Commission accepted the proposed language as described above.[681] We also note that there are two cooperatives Hoosier Energy Rural Electric Cooperative, Inc. and Wabash Valley Power Association that are members of the Midwest ISO.[682] We are hopeful that similar agreements between RTOs and public power entities and cooperatives can be reached to provide flexibility and achieve broad regional RTO participation by all entities.

We expect public power entities and cooperatives to participate fully in the collaborative process for forming RTOs. During the collaborative process, the Commission hopes that the parties will explore, in detail, the impediments and various solutions to public power and cooperative participation in RTOs. As discussed below with respect to the collaborative process, we will make staff resources available to assist in facilitating communication between all entities and in designing regional solutions to full RTO formation and participation. Moreover, in all filings under this Rule, we require a description of efforts made to accommodate participation by public power entities and cooperatives in RTOs.

We recognize that there is uncertainty regarding what may happen after the IRS temporary ''private use'' regulations expire on January 22, 2001. Accordingly, we intend to continue to support efforts to mitigate the ''private use'' and other tax restrictions. Furthermore, in its comments, RUS recognizes that the development of RTOs may offer considerable benefits to RUS borrowers. RUS states that it is exploring means to facilitate borrower participation in RTOs. The Commission welcomes the efforts of RUS to facilitate borrower participation in RTOs, and also encourages RTOs to seek ways to accommodate mortgage restrictions. It would be unfortunate if public power entities and cooperatives were not able to participate in RTOs and share in the benefits available in a regional organization because of tax rules and other government restrictions.

2. Participation by Canadian and Mexican Entities

In the NOPR, the Commission noted that currently, electricity trading regions exist across national borders and therefore, Mexican and Canadian involvement in RTO formation would be beneficial to both countries, as well as to the United States.[683] The Commission asserted that regional institutions should include all market participants in order to provide direct access to information and the benefits of non-pancaked rates. The NOPR also proposed that in order to prevent wasteful duplication of grid facilities, reliability standards implemented by RTOs must be acceptable to the affected nations.[684] The Commission also emphasized that Canadian and Mexican authorities would be responsible for approving prices and other terms and conditions of transmission service provided over any RTO transmission facilities located in their country.[685]

Comments. The U.S. entities that submitted comments on this issue support the efforts by the Commission to encourage participation in RTOs by Canadian and Mexican entities.[686] For example, PG&E states that given the high degree of operational interconnection between our national grid and components of their systems, participation by these entities is beneficial.

Similarly, some Canadian entities believe that significant benefits can be achieved by trading over ''natural'' or ''appropriate'' transmission regions that do not necessarily stop at the border.[687] Other Canadian entities welcome the opportunity to participate in the RTO proceedings and support the Commission's efforts to encourage international collaboration.[688]

Canadian entities are concerned with sovereignty issues and urge the Commission to adopt flexible RTO rules that allow voluntary participation by Canadian utilities.[689] According to the Manitoba Board and Ontario IMO, one option in this regard would be to allow members of an RTO the freedom to conduct transactions—through a contractual relationship—at the international border with foreign utilities that do not join a cross-border RTO. Furthermore, Canada DNR asserts that a decision not to participate in an international RTO by a Canadian jurisdiction should not place entities in Canada engaged in trade with United States at a disadvantage. Grand Council *et al.* proposes that the Commission sever the Canadian issues from this proceeding and open a separate docket to examine the international issues raised by the restructuring of electricity markets. Grand Council *et al.* urges the Commission to cooperate with Canada and Mexico to establish a genuine tri-national consultative process in order to resolve international issues based on an adequate record. Alberta notes that each

[680] *See* Central Hudson Gas & Electric Corp., *et al.,* 83 FERC ¶ 61,352 at 62,405 (1998).

[681] *See* Central Hudson Gas & Electric Corp., *et al.,* 88 FERC ¶ 61,138 at 61,402–03 (1999).

[682] *See* Midwest Independent Transmission System Operator, Inc., *et al.,* 84 FERC ¶ 61,231 (1998).

[683] FERC Stats. and Regs. ¶ 32,541 at 33,758.

[684] *Id.* at 33,758–59.

[685] *Id.* at 33,759.

[686] *See* PG&E, Desert STAR, Michigan Commission and Industrial Consumers.

[687] *See, e.g.,* Ontario Power, H.Q. Energy Services, BC Hydro and Canada DNR.

[688] *See, e.g.,* Powerex, CEA, Manitoba Board, British Columbia Ministry, Alberta, Canada DNR, BC Hydro and Ontario IMO.

[689] *E.g.,* Manitoba Board, British Columbia Ministry, BC Hydro, Canada DNR, CEA and Ontario Power.

individual Province has jurisdictional responsibility for the development of the electrical industry within each Providence and accordingly, only the Province has the jurisdiction to pass legislation to develop a competitive electricity market.

Commission Conclusion. After reviewing the comments, we continue to believe that Canadian and Mexican involvement in RTO formation and operation would be beneficial to both countries, as well as to the United States. As we stated in the NOPR, expansion of electricity trade in the North American bulk power market requires that regional institutions include all market participants so that everyone may enjoy direct access to market information and the benefits of non-pancaked transmission rates. Commenters from the United States and Canada agree that significant benefits can be achieved by trading over ''natural'' or ''appropriate'' transmission regions that do not necessarily stop at the border.

We note first that we are pleased with the level of participation in our proceedings by Canadian parties, and we encourage their continued participation as RTO formation progresses. We especially appreciate the RTO Consultation Conference sponsored by Natural Resources Canada in Ottawa in November 1999.

In response to Canadian comments, we point out that the Final Rule makes participation in an RTO voluntary for U.S. transmission owners, and participation is certainly voluntary for Canadian transmission owners. Further, we emphasize that our RTO Rule does not in any way require competition in retail electricity markets, whether they are located in the United States under state regulation or in Canada under provincial regulation. For those Canadian entities that want to join an RTO, the Final Rule is flexible: they may propose a cross-border RTO or a Canadian-only RTO that is compatible with the Rule. The Final Rule is not exclusionary: Canadian entities are not precluded from joining a cross-border RTO.

Several parties were concerned that a cross-border RTO would have its rates, terms, and conditions subject to the rate jurisdiction of at least two regulators. If a cross-border RTO forms, we will be open to proposals for innovative approaches for jointly overseeing a cross-border RTO with domestic and foreign utilities. For example, one approach might be for the cross-border RTO to try to develop a proposal acceptable to both regulators, with the understanding that any regulatory difficulty would normally be referred back to the RTO for resolution and resubmission to both regulators. Another approach might be to have different but complementary rate designs in the two countries.

In the case of a Canada-only RTO, some Canadian transmission providers believe that having contractual and other agreements for coordination between separate RTOs aross the border is better than having a cross-border RTO. However, some Canadian transmission customers are concerned that this would maintain a lack of standardization of market rules across the border. The RTO Rule is intended to permit a U.S. RTO on the Canadian border to develop contractual and other agreements for coordination with its Canadian RTO neighbor. Further, we have added a new minimum RTO function that an RTO must ensure the integration of reliability practices with other regions in the same interconnection and market interface practices with other regions. We clarify here that this provision applies to integration with interconnected regions in Canada and Mexico.

For either a cross-border or a Canada-only RTO, we acknowledge the sovereign authority of Canadian governments over Canadian entities and transactions that take place in Canada. Moreover, we re-emphasize that our Rule does not affect the authorities of Canadian government entities to approve prices and other terms and conditions of transmission service provided over any transmission facilities located in Canada. These conclusions apply equally to Mexico.

We encourage Canadian and Mexican entities to participate in continued RTO consultations and, if appropriate, formation and filings for cross-border RTOs. In particular, we urge Canadian and Mexican entities to attend the appropriate regional workshops to be held in the spring of 2000. These workshops will provide a forum for initial discussion of the issues associated with a cross-border RTOs.

Regarding the suggestion to establish a tri-national consultative process with Canadian and Mexican authorities to resolve international electric industry issues, we note that there are existing institutions and processes for resolving international disputes. The RTO process is just getting underway, and it is not clear that significant international disputes will develop or, if they should develop, that they would require a non-traditional method of resolution. Indeed, the RTO itself through its dispute resolution process may provide a new and quicker way to resolve some disputes.

3. Existing Transmission Contracts

In the NOPR, the Commission asked for comments addressing what the appropriate treatment should be for existing transmission agreements when an RTO is formed. We noted that in Order Nos. 888 and 888–A, the Commission specifically chose not to abrogate existing requirements contracts and transmission contracts when the utility filed an open access transmission tariff.[690] We stated, however, that an RTO represents an entirely different context. In the NOPR, the Commission recognized the importance of balancing a uniform approach for transmission pricing with the equities inherent in existing transmission contracts.[691] Furthermore, we noted that the potential financial impact of giving up an advantageous transmission arrangement may serve as a disincentive to joining an RTO. In the NOPR, we proposed to address the issue of existing transmission contracts on an RTO-by-RTO basis, rather than resolve the issue generically.[692]

Comments. Many commenters argue that the Commission should preserve and protect existing transmission contracts.[693] These commenters note that existing contracts represent negotiated rights and obligations achieved through mutual negotiation. SRP believes that the Commission should grandfather existing transmission contracts in order to protect customers from cost shifts and prevent uncertainty in the marketplace. Turlock argues that the preservation of existing contracts, while cumbersome, is the bedrock of predictability and reliability and a key element of contract law. NPRB states that existing contracts should be honored until the contract expires or until the parties come to a new agreement. STDUG asserts that in order to be properly inclusive, an RTO must take members as it finds them, existing contracts, warts, and all. In contrast, CP&L asserts that the elimination of grandfathered agreements to the greatest extent possible ensures the most level playing field for all market participants.

[690] FERC Stats. & Regs. ¶ 32,541 at 33,757.

[691] *See id.* at 33,757–58.

[692] *Id.* at 33,758.

[693] *E.g.,* TANC, Turlock, UAMPS, Desert STAR, CMUA, Sithe, Georgia Transmission, Lincoln, PG&E, NPRB, NCPA, Great River, NRECA, Loveland Customers, San Francisco, Platte River, Florida Commission, Nevada Commission, DOE, Wolverine Cooperative, Tri-State, CREDA, EPSA, Big Rivers, SPP, SoCal Cities, TEP, PJM/NEPOOL Customers, Metropolitan, STDUG and PacifiCorp.

A few commenters propose a reasonable transition period to allow parties to existing contracts to conform their arrangements to an RTO tariff.[694] EPSA notes that the transition period should be of sufficient length to reduce the financial and other burdens on the customer and on the original transmission provider. PSNM argues that at a minimum, a transition period of as long as ten years is needed to move the existing transmission contracts to RTO service. Furthermore, TAPS proposes that the Commission provide entities with an open season for transmission customers to choose to terminate or switch service under the terms of an RTO tariff. Alternatively, TAPS suggests that the Commission apply a just and reasonable standard to all transmission customers who seek contract modifications. Regarding contract modification, Southern Company asserts that in order to promote fairness, both parties to a contract must have an equal opportunity to modify the existing agreement. In addition, Entergy argues that the Commission should encourage all entities to re-negotiate existing contracts.

Several commenters support the Commission's preference that issues relating to the continued validity of existing transmission contracts be addressed on an RTO-by-RTO basis.[695] WPSC argues that treatment of existing transmission contracts within a particular RTO should be consistent. Turlock urges the Commission to proceed with caution when addressing existing contracts. On the other hand, PSE&G asserts that the Commission should not address the treatment of existing contracts on a case-by-case basis because this leads to arbitrary and inconsistent results. Instead, PSE&G and Dalton Utilities argue that the Commission should address the issue of existing transmission contracts on a generic basis consistent with Order No. 888 and the Mobile-Sierra doctrine (recognizing the need to preserve the sanctity of contracts where possible).[696] Sithe and NRECA concur that a generic policy is appropriate.

Cal ISO argues that the Commission's policies on existing contracts deserve revisiting, at a minimum for the limited purpose of conforming scheduling and metering rules to those of the RTO/control area operator. Cal ISO states that it has experienced the challenges of workability when the ISO was required to honor existing contracts, but not permitted to interpret them or conform their scheduling rules to those of the regional organization. Cal ISO notes that it has experienced the most significant market inefficiencies associated with existing contracts in the area of scheduling and information gathering.

A few commenters note that not honoring existing contracts would create disincentives for both transmission customers and owners to join an RTO.[697] For example, CMUA and Georgia Transmission argue that the financial impact of giving up an advantageous transmission arrangement would be a significant disincentive to RTO membership.

Commission Conclusion. At this time, we continue to believe that it is not appropriate to order generic abrogation of existing transmission contracts. We recognize that existing contracts represent negotiated rights and obligations achieved through mutual negotiation. However, in PJM[698] and the Midwest ISO[699] we adopted the rationale that it was unreasonable and discriminatory to maintain the pancaked rates in existing contracts for others when transmission-owning utilities had designed a non-pancaked rate approach for their own transactions. In our examination of existing contracts, we intend to balance the preference for preservation of existing contracts with the importance of consistency in transmission pricing and the elimination of pancaked rates.

As the above comments demonstrate, there is no consensus on how the Commission should manage the transition from existing transmission contacts to RTO service. In fact, parties offer diverse and conflicting views as to what the Commission should do regarding existing transmission contracts. Some commenters would have us let all contracts run their course with no opportunity to modify or terminate. Others advocate an elimination of existing agreements to the greatest extent possible. Yet others argue for a transition period ranging in duration for up to ten years to move existing transmission contracts to RTO service.

Rather than adopting one extreme position or the other, we will take a measured approach with regard to the treatment of existing transmission contracts. We intend to address the issue of existing transmission contracts on an RTO-by-RTO basis, rather than resolve the issue generically. Accordingly, each RTO can propose whatever contract reform is necessary, including the limited changes suggested by the Cal ISO for the limited purpose of conforming scheduling, information gathering, and metering rules to those of the RTO. To this end, we encourage each RTO to address how and when it might convert existing contracts and submit a contract transition plan that contains specific details about the procedures to be utilized involving the conversion from existing contracts to RTO service. Again, our goal in reviewing existing transmission contracts and contract transition plans is to balance the desire to honor existing contractual arrangements with the need for a uniform approach for transmission pricing and the elimination of pancaked rates.

4. Power Exchanges (PXs)

The NOPR described the apparent advantages and disadvantages of having a power exchange coincident with an RTO. As further described in the NOPR, supporters state that PXs can reduce price volatility by providing price transparency, reduce the impact of defaults by spreading transaction risks among all participants through credit standards and reserve fund requirements, facilitate risk hedging by providing a basis for a futures market, and help facilitate retail access programs. Detractors argue that the principal functions of a PX are not natural monopoly functions. They contend that PXs, compared with bilateral markets, force participants to buy and sell electricity using standardized contracts, which may not suit their particular needs. They further argue that competition within the electricity market and its full benefits can only be achieved if there is competition for the PX market.

The NOPR left it to each region to determine whether there is a need for a power exchange and whether the RTO should operate it.[700] The NOPR said that the Commission will accept any RTO proposal that includes a power exchange in its design as long as its operation of the power exchange does not compromise its independence as a

[694] *See, e.g.,* Williams, EPSA, First Energy, Duke, PSNM, LG&E, PGE and MidAmerican.

[695] *See, e.g.,* WPSC, Great River, DOE, ICUA, Entergy, TDU Systems, TEP, South Carolina Authority, MidAmerican, SNWA, UAMPS and TAPS.

[696] *See* United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 338 (1956); FPC v. Sierra Pacific Power Co., 350 U.S. 348, 353 (1956).

[697] *E.g.,* CMUA, Desert STAR, Georgia Transmission, Wolverine Cooperative, Cal ISO, Entergy, Tri-State, SNWA, Metropolitan and TEP.

[698] *See PJM,* 81 FERC ¶ 61,257 at 62,280–81 (1997).

[699] *See* Midwest Independent Transmission System Operator, Inc., *et al.,* 84 FERC ¶ 61,231 at 62,169–70, *order on reh'g,* 85 FERC ¶ 61,372 at 62,418–20 (1998).

[700] FERC Stats. and Regs. ¶ 32,541 at 33,760.

transmission service provider. The Commission sought comments on a number of questions related to power exchanges, including whether regional flexibility is appropriate and how RTOs should deal with an independent power exchange.

Comments. Commenters' views on power exchanges are mixed. The largest group of commenters basically agree with the NOPR.[701] A smaller group of commenters recommend that the Commission require that RTO applications include provisions for a power exchange,[702] with some recommending that the power exchange be internal to the RTO [703] and some recommending that the PX be independent of the RTO.[704] CalPX argues strongly that a power exchange should be separate from the RTO, given the continuing need to separate market and transmission functions; the need for market transparency to facilitate determination of whether congestion is being exploited; the need to provide a credible reference price for new retail choice market entrants; and the potential need for the RTO and power exchange to serve differing geographic areas. CalPX also submits that there is no concrete evidence that an RTO-operated power exchange will be more efficient and economical than an unrelated power exchange. NYMEX agrees that an RTO should be permitted to operate a power exchange, as long as a proper code of conduct is in place. PJM points to its success with a combined ISO/power exchange.

Another group of commenters argue that power exchanges should not be included in RTOs, but should be allowed to occur naturally as needed.[705] Elaborating on this point of view, Salomon Smith Barney advises that the power exchange should not be in the RTO because it could throttle innovation and that the Commission should let the market decide. If there are really advantages to be gained, as some claim, from the operation of a single power exchange associated with the RTO, then such a power exchange will naturally develop. Florida Power Corp. argues that, while a region may prefer that its RTO closely coordinate with the power exchange, the two should not be part of the same organization because there is a fundamental difference in the business objectives of the two .

[701] *See, e.g.,* Entergy, NJBUS, NY ISO, TDU Systems, Wisconsin Commission and UtilitCorp.

[702] *See, e.g.,* Pennsylvania Commission, Duke and California Board.

[703] *See, e.g.,* PJM, ISO-NE and TAPS.

[704] *See, e.g.,* EPSA and MidAmerican.

[705] *See, e.g.,* APX, SMUD, Southern Company, Tri-State and Lincoln.

Similarly, EPSA contends that the Commission's vision of an RTO being an entity independent from all generation and power marketing interests is fundamentally incompatible with an RTO-run power exchange. Nevada Commission offers that a power exchange is not necessary to the formation of an RTO. And while PG&E sees every region needing a real-time balancing market regardless of whether it is run in-house by the RTO, PG&E also prefers that markets should otherwise be left to develop on their own accord.

Comments were received on additional aspects of the power exchange concept. PG&E argues that an RTO should not be allowed to use control of a power exchange to alter or cap prices set by the market. LG&E submits that the RTO should be required to be the provider of last resort for ancillary services, although market participants should not be required to purchase from the RTO. NASUCA notes that the NOPR does not cover some important power exchange issues such as exactly which markets would be included. NASUCA recommends that a NOI on power exchanges and related power market issues be initiated soon after the final rule.

Several commenters state that multiple power exchanges in a region should have equal standing before the RTO.[706] FTC, however, recommends that the Commission assess whether competition is feasible in power exchange services. Similarly, CalPX notes that multiple power exchanges may hurt the market's function because each power exchange would be small, and therefore would not offer high levels of depth, liquidity and efficiency. NYMEX counters that there should be no credence given to the idea that one power exchange should enjoy any form of artificial franchise vis-a-vis others.

Commission Conclusion. The NOPR proposed leaving it to each region to determine whether there is a need for a power exchange and whether the RTO should operate the power exchange. We have Decided to adopt the NOPR proposal. As the commenters have pointed out, there are advantages and disadvantages to the inclusion of a PX in the RTO structure. We do not believe that including a PX as part of the RTO structure would necessarily preclude the market benefits associated with bilateral transactions. We believe an RTO can accommodate both a bilateral market and a PX market. As the individual structures of the various RTOs supported by the regions are

[706] *See, e.g.,* Duke, Florida Power Corp. and Desert STAR.

likely to be quite varied, we think that it is best to let market preferences dictate the form of any one or more regional power exchanges and whether the RTO should operate a power exchange.

5. Effect on Retail Markets and Retail Access

The NOPR addressed the impact of RTOs and any associated PXs on retail competition and the states' jurisdiction over retail competition. For example, the Commission found that RTOs will enhance the effectiveness of retail competition:

> We believe that the likelihood of success for existing and planned retail choice initiatives is significantly enhanced if the Commission can ensure fair and efficient access to a regional market without pancaked transmission access charges, and that we need to take steps beyond Order No. 888 to accomplish this.[707]

In addition, the Commission found that an RTO does nothing to interfere with the state's authority to decide retail access policy, but asked whether a PX is necessary for successful retail competition.

Comments. Several commenters state that RTOs were either essential or of great benefit in the implementation of retail competition.[708] Mid-Atlantic Commissions notes that PJM has worked closely with the Pennsylvania, New Jersey and Delaware Commissions to assist with the implementation of their retail choice legislation in an organized fashion, while maintaining that the grid will be operated in a reliable fashion without any major economic or operational changes. According to Mid-Atlantic Commissions, this has also further provided those states in the region that have not implemented retail choice with a stable organization that continues to maintain reliability.

A few commenters express concern that the Commission's RTO policy could threaten the states' ability to control the pace of retail access and retail competition.[709] South Carolina Commission counsels that the Commission should try to avoid affecting retail restructuring through its efforts to establish an RTO process. Central Maine raises the concern that retail choice programs already developed in concert with existing ISOs may be adversely impacted by any changes to such ISOs that are found to be necessary for them to conform to the RTO requirements (*e.g.*, energy service

[707] FERC Stats. and Regs. ¶ 32,541 at 33,704.

[708] *See, e.g.,* TXU Electric, DOE, First Rochdale, Illinois Commission and Williams.

[709] *See, e.g.,* Iowa Board and Puget.

company and other load serving entity contracts entered into in reliance upon the existing ISO market structures).

Puget views allowing RTOs to make FPA section 205 filings that unilaterally propose changes to the RTO tariff as conflicting with the Commission's commitment to respect the retail access efforts of the individual states. Puget argues that a unilateral decision by an RTO to provide transmission service to a retail customer and make that customer an eligible customer under the *pro forma* tariff would force states without retail access to accept such access as a *fait accompli.* Puget also fears that the term ''market participant'' as ultimately defined may include any entity that buys or sells electric energy in the RTO's region or in any neighboring region that might be affected by the RTO's actions. If so, since market participants must also have the option of self-supplying or acquiring ancillary services from third parties, this further suggests that retail customers may have the ability to acquire transmission service regardless of whether the affected state has yet decided retail choice and stranded cost recovery issues. Industrial Customers, however, question the legal basis for Puget's apparent suggestion that utilities be allowed to decide which retail customers may access RTO transmission.

EPSA contends that, while states tout each state's rights to protect its retail native load customers, some actions taken under this banner to limit exports of power actually disadvantage adjoining state's retail customers or participants in the bulk power markets. Therefore, the Commission should move forward with a rulemaking to assure full transmission comparability for retail customers of all states, and to prevent individual states from continuing to disadvantage each other and to prevent individual utilities from continuing to disadvantage other market participants. New York Commission also submits that this proceeding is not the place to address the issue of preemption of state jurisdiction over bundled retail electric sales.

TAPS raises the question of jurisdictional conflict as to which facilities need to be regulated at the federal or state level, and whether the policies of the Commission toward open access will be undercut by transmission owners using the seven factor transmission/distribution classification test to place new generation at a disadvantage relative to existing generation owned by the transmission provider. TAPS contends that the Commission must take steps to ensure that RTOs contain the appropriate facilities and that refunctionalization of transmission to distribution does not interfere with competition by creating RTOs that control little or no transmission.

Another concern expressed is that RTOs may cause cost shifting to retail customers that could interfere with restructuring.[710] As to the impact of the power exchange on retail competition, both CalPX and MidAmerican argue that power exchanges assist in the effectiveness of retail competition programs by providing transparent and credible reference prices.

Commission Conclusion. We continue to be persuaded that RTOs can positively affect each state's implementation of its retail choice program, without interfering with those states that have not yet adopted such programs. As noted by commenters, existing ISOs have already successfully facilitated retail choice programs in areas where only some of the states have adopted such programs, and the ISOs were able to do so without clashing with or frustrating the other states that have not undertaken such programs. We do not believe that an RTO could interfere with a state's decisions on whether or how fast to implement retail choice within its borders, either through the RTO's Section 205 filing authority or otherwise through the RTO's jurisdictional obligation to provide non-discriminatory and non-preferential transmission service.

Commenters pointed to potentially extensive reclassification of transmission facilities to local distribution as part of the unbundling of retail rate schedules to implement retail choice programs, and how this might lead to RTOs that are ''empty vessels'' with little significant transmission under their control. We agree that RTOs must control all transmission facilities that are necessary to support competitive wholesale power markets. For this reason, we specified the scope, configuration and operational control requirements adopted in this Final Rule. We will judge any proposed reclassification on a case-by-case basis. We note that any reclassification of transmission facilities to local distribution will require Commission approval and will not remove from the Commission's jurisdiction any facilities used to deliver power to wholesale customers. Furthermore, under the principle of open architecture (discussed *supra* in section III.F), the Commission expects RTOs to remain flexible such that, if over time circumstances should change and certain facilities need to be reclassified as transmission, procedures will be in place to do so.

With regard to RTO pricing causing transmission cost shifting that adversely affects retail choice customers, this issue is discussed in the Transmission Ratemaking section of this Final Rule.[711] The Commission will continue to review transmission rate proposals to ensure that they are just and reasonable, and not unduly discriminatory.

Finally, on the matter of whether a power exchange is needed to facilitate states' retail choice programs, it is our view that, to the extent that a region forming an RTO chooses to voluntarily establish an RTO-affiliated power market, we anticipate that any such power exchange would provide retail choice customers with transparent and credible reference prices for power and other information that otherwise might not be available.[712]

6. Effect on States with Low Cost Generation

In the NOPR, we recognized that states with relatively low cost power are concerned that an RTO would result in local utilities selling their low cost power to other states.[713] However, we noted that a state that is low cost today may not be low cost tomorrow without an RTO in its area.[714] In addition, we stated that utilities that now have low cost generation will help assure access to future low cost generating plants by participating in an RTO and that new low cost generation plants are more likely to be attracted to regions with a well-functioning regional market governed by an RTO. We sought comment from state commissions regarding how an RTO in their state would affect power costs.

Comments.—A number of commenters raise concerns about the effect of RTOs on states with low cost electricity. These concerns center around one issue—that the costs of creating an RTO may outweigh the benefits.

South Carolina Commission argues that customers in South Carolina enjoy very high quality service and pay some of the lowest rates. Duke power concurs, noting that, it is not necessarily true that North Carolina and South Carolina will conclude that sufficient long-term benefits exist for these states to justify costs of RTO membership. Duke argues

[710] *See, e.g.,* LG&E and Southern Company.

[711] *See supra* section III.G.

[712] For a further discussion of PXs, *see supra* section III.H.4.

[713] FERC Stats. and Regs. ¶ 32,541 at 33,722.

[714] *See id.*

that any proposed RTO should be shown to provide tangible benefits to the relevant region.

Alabama Commission believes that RTOs will cause states to lose the efficiency of integrated systems and lead to retail competition, whether it is in the interest of customers or not. Southern Company agrees, noting that due in large part to the low cost status of southeastern states, they are proceeding cautiously with retail competition and restructuring initiatives. This does not mean that these states are ignoring the potential benefits of restructuring. Indeed, Southern Company notes that states in its service territory are actively studying the potential advantages and disadvantages of retail competition but have not yet concluded that the potential benefits outweigh the costs and risks associated with changing the current industry structure.

SMUD points out that it has not joined the Cal ISO over similar concerns. It indicates that its customers already enjoy low cost electricity and that participation in the Cal ISO could not ensure that SMUD's retail rates would be any lower, and on the contrary, the cost of participation would cause rate increases.

Kentucky Commission indicates that inefficiencies may occur for a variety of reasons and examples of inefficiencies include: multiple RTOs in a small region; several layers of governance within one RTO; and too many tasks shifted from the RTO members to the RTO itself. Kentucky Commission argues that if the proposed transmission organizations are not operated at levels of maximum efficiencies and minimum reasonable costs, the Commission will have failed to promote one of its primary objectives, the growth and success of the wholesale power market. Kentucky Commission further argues that the Commission must be mindful of these costs in developing rules for the establishment of RTOs.

Commission Conclusion. We are mindful of the potential costs of setting up and running an RTO, but we anticipate that the collaborative process will result in an RTO proposal that incorporates a design that, overall, increases the existing level of transmission system and market efficiency for each region. As we discuss more fully in the Scope, Implementation and Benefits sections of this Final Rule, we are taking a results-oriented, practical approach to establishment, organization, implementation and operation of RTOs. We do not expect that regions with no existing institutions will necessarily invest in new, high-cost RTO infrastructure. Instead, such a region may propose an RTO that relies on existing infrastructure to accomplish its mission. However, we expect the RTO to satisfy the minimum characteristics and functions and to improve the efficiency of regional transmission service.

In response to the concern of low cost states that RTOs could result in exports of their low cost power to other states, we do not believe that an RTO will cause utilities to sell their lowest cost power out of state. While retail choice arguably might lead to low cost power being sold out of state because incumbent utilities no longer have an obligation to serve local in-state loads, this would occur with or without an RTO in the region. Where there is no retail choice, our Final Rule does not affect a state commission's authority to require a utility to sell its lowest cost power to native load, as it always has. We point out that, if the utility's transmission is operated by an RTO and its higher cost power can be sold more readily to new, more distant customers, this will lead to recovery of more capital costs and lower retail rates. In the long term, low cost states may benefit from an RTO that facilitates expanded access to wholesale electricity markets, increasing the choice of low cost resources available to utilities as they acquire new power resources.

7. States' Roles with Regard to RTOs

In the NOPR, we noted that states want a role in the governance of any RTOs for their states, and we proposed to be flexible in accommodating the states' needs.[715] The NOPR encouraged RTO design to accommodate appropriate state oversight, especially with regard to planning and siting new multi-state transmission facilities. We sought comments on the appropriate state role in RTOs on these and other RTO matters.

Comments. Comments on the states' roles in RTO development and governance were fairly extensive, with by far the greater percentage of comments supporting a strong and clearly defined state role. Comments can be grouped into four primary categories: (1) governance; (2) formation; (3) siting and planning authority; (4) regional regulation.

Governance. Almost all commenters on this issue expressed support for a clear state role in governance; however, there were differences as to exactly what that role should be. Some commenters believe that states should be allowed to determine their own role in governance, either as members of advisory panels to the board of directors, as voting members of the board, as non-voting members of the board, or having authority to appoint board members. Some commenters, however, feel strongly that states should not be permitted to be voting members of boards.

Commenters argue that the appropriate state role in an RTO is a matter of local control. For example, Northwest Council states that the Commission should not set restrictive rules on the type of state participation in RTO governance, but should allow the states to propose to the Commission the kind of roles they view as appropriate, *e.g.*, voting members of a stakeholder board, *ex officio* status on an independent board, and so forth.

The California Board suggested that state officials should be allowed as either voting or non-voting members. Los Angeles has no objection to state board membership, either voting or non-voting, if a state has determined that a government official can best represent that state's interests. The Washington Commission agrees that states should be able to define their own role. Mid-Atlantic Commissions note that they have a Memorandum of Understanding with the PJM ISO Board of Managers to facilitate communication and promote a cooperative relationship.

Some commenters, however, think that state officials should not have voting membership on boards of directors since that could raise conflict of interest problems where the state official would have to approve decisions of the board while sitting as a regulator. For example, Minnesota Power believes that state cooperation will be enhanced if state officials participate as members of an RTO advisory board, but they should not participate as voting members of an RTO because the RTO process could be compromised by parochial state politics. ISO–NE agrees, pointing out that some states' conflict of interest laws may expressly prohibit such service, and that it might be difficult for an official from one state to make decisions as a board member that are good for residents of all states encompassed by the RTO.[716] WEPCO believes the appropriate role of the states in RTO governance includes active participation in regional planning efforts and continued oversight of siting of new transmission facilities. In addition, many commenters supported

[715] FERC Stats. and Regs. ¶ 32,541 at 33,724.

[716] *See also* MidAmerican, Montana-Dakota, PSNM, East Kentucky and NPRB.

an advisory role for state officials, through advisory boards.[717]

Formation. Numerous commenters supported a role for states in the formation of RTOs. ISO–NE points out that the states in its region had a significant role in the development of the ISO. In addition, the California Board argues that states should have a role in determining the structure of the RTO and any other market institutions that are formed to serve the citizens of their respective states. California Board further notes that mechanisms to ensure that states' interests are protected might include statutory or regulatory reliability criteria; independent market monitoring by the states or requiring market monitoring reports to be provided to the state; and accountability to the states to ensure adequacy of transmission and generation planning.

The Michigan Commission notes that most states have ittle direct authority to order the development of an RTO, especially when the RTO encompasses several states. According to the Michigan Commission, at best state commissions should serve in an advisory role as the utilities develop the structure and guidelines of the RTO proposal. The Michigan Commission, however, joins a few other states in urging the Commission to defer to state recommendations once the basic RTO characteristic and functional guidelines have been met.

NARUC comments extensively on the potential collaborative process and the importance of state participation in this process and other steps in the formation of RTOs. To achieve the public policy goal of assuring reliable service at an affordable cost, NARUC argues that states should fully participate in RTO development and formation, particularly in matters for end-use native load customers. NARUC notes that based on some states' retail choice or ISO experiences, state oversight can play a significant role in assuring a well-functioning ISO and competitive wholesale and retail markets.

NARUC further suggests that once RTOs are formed, continuing interaction is necessary, and market development and evolution will be continuous. NARUC believes that RTO formation must continue to be a dynamic process requiring continuing dialogue between FERC and the states. NARUC further believes that once organizations are formed and approved, some type of formal reporting to FERC and the states by the organizations on an annual basis would be appropriate.

Nine Commissions suggests that state commissions are well positioned to balance the competitive motivations of utilities in the RTO formation process with the interests of all other stakeholders in defining markets in their respective regions and conforming the RTO boundaries to those markets. According to Nine Commissions, the state commissions' continued cooperation with FERC will ensure that the mutual public interests of providing reliable electric service will be met, and that market participants in every region of the country will be treated comparably.

Siting, Planning and Reliability. A number of commenters, many state commissions, and quite a few other parties, argue strongly that the Commission should be careful not to preempt traditional state regulatory authority in promulgating its rule. In particular, commenters suggest that the Commission should not usurp state authorities over siting, planning, and reliability of the transmission system. Some commenters proposed solutions to state/Federal jurisdiction issues in the RTO context, such as joint state/Federal review bodies. The Alabama Commission suggests that FERC should not take any action that would infringe on state jurisdiction.

South Carolina Commission asserts that transmission siting should remain in the hands of the states and local governments. South Carolina Commission further asserts that states must continue to have a significant role with regard to matters of reliability for end-use native load customers. The Iowa Board concurs and suggests that the Commission's RTO policies cannot alter states' continued interest in local matters such as transmission and generation siting, local transmission and distribution interface issues, adequacy of generation and transmission, service quality, and retail rates.

The Montana Commission notes that in roughly half the states with siting laws the function is not vested in the regulatory commission, but rather in a separate energy policy, environmental or commerce agency. They recommend that the Commission amend the language in the Final Rule to make it clear that the Commission does not intend to preempt state siting authority as part of this NOPR.

UAMPS warns that RTOs may create a separation between generation planning and transmission planning that endangers reliability. UAMPS argues that states must be left with authority to assure reliability and that retail competition issues should also be left to the states. UAMPS suggests that because state cooperation and participation will be so critical to an RTO's effectiveness, in addition to the four minimum characteristics the Commission has proposed, RTOs should be required to provide specifically for significant state involvement in their development and operation. Allegheny, on the contrary, states that system operations in an RTO will be pursued for the good of the RTO service area, not of any one state. Allegheny notes that if that fact yields a dilution of state authority it must be the price paid for RTO benefits.

Regional Regulation. A number of commenters propose or support regional regulatory cooperation or joint state/Federal sharing of jurisdiction. The Kentucky Commission proposes the creation of a Federal/state ''joint board,'' that is styled similarly to the Universal Service Joint Board currently used by the Federal Communications Commission, state utility commissions, and other parties. The Kentucky Commission suggests creating this voluntary Board to develop and review standards for transmission expansion. The Joint Board would include participation from FERC, state commissions, RTOs, and other interested parties. The Joint Board would also convene ad hoc committees to review specific transmission expansion proposals. These committees would include the participants described above, and would include representatives from regulatory commissions in states where the expansion is proposed. The RTO would present the *ad hoc* committee with a plan for transmission expansion with appropriate documentation for need, cost effectiveness, and alternatives. The committee would in turn pass on its recommendation or refusal of support for the plan to the specific state commissions for their official approval. The Kentucky Commission believes that such an arrangement could avoid Federal/state conflict while allowing both levels of government to exercise appropriate jurisdiction. In addition, ISO–NE points to existing regional regulatory groups such as NECPUC that could continue to provide valuable assistance to the Commission in the collaborative process to encourage RTO formation envisioned in the NOPR.

Nine Commissions argues that an appropriate regional oversight venue will lead to more consistent treatment of issues and parties between state and Federal regulatory forums. With appropriate deference by both FERC and the states, such a regional venue could

[717] *E.g.,* ISO–NE, PJM, Midwest ISO, MidAmerican, Project Groups, PSNM, Iowa Board, Arizona Commission and UAMPS.

obviate the need for many parties to expend redundant resources to participate in multiple state and Federal regulatory processes for matters relating to transmission and RTOs.

Nine Commissions notes that one possible mechanism to effectuate such a regional venue is interstate compacts, which are provided for in the Administration's proposed electric industry restructuring legislation. Nine Commissions argues that regional regulatory organizations have the advantage of being able to coordinate state interests for providing regional recommendations to FERC. State oversight functions (*e.g.* siting, local outages, customer complaints) would not change. According to Nine Commissions, such regional regulatory organizations would provide greater coordination among states within the region, allowing for ADR processes that could satisfy multiple state jurisdictional requirements, and such organizations would monitor markets that have evolved beyond state borders and facilitate joint FERC and multi-state facilities siting.

Pennsylvania Commission prefers a joint Federal/state approach toward regulating RTO siting approvals, expansion, innovation and customer service. Pennsylvania Commission notes that a joint approach would resolve the vexing problem of Federal/state jurisdictional uncertainty and a joint Federal/state approach would avoid the potential for creative forum shopping by individual stakeholders, who will always seek to cast a dispute in jurisdictional terms so as to dictate a jurisdictional resolution to the perceived favorable outcome. A joint Federal/state approach has been used with success in other areas, such as the Susquehanna River Basin Commission, the Delaware River Basin Commission and the Joint Pipeline Office for the Trans-Alaska Pipeline System. Likewise, the Virginia Commission believes that there is no conflict between state goals and Commission goals and that the two levels of government should be able to work together and avoid conflict as long as both parties recognize that the common goal is the public interest.

Commission Conclusion. We continue to believe that states have important roles to play in RTO matters. For example, most states must approve a utility joining an RTO, and several states have required their utilities to turn over their transmission facilities to an independent transmission operator. Also, states must approve the siting of transmission facilities that are called for in an RTO expansion plan.

We believe, however, that it is not appropriate to try to set out a full set of states' roles in this Rule. It is difficult, and not necessary, to reach generic conclusions about states' roles given the diversity of possible RTO forms and state authorities. For example, a state's role may be different for an ISO, transco, and other organizational form, and it may be different for a multistate RTO and a single-state RTO, if any. States differ regarding the authorities they have vested in their regulatory and siting agencies. Further, states differ regarding their jurisdiction over municipal and cooperative utility owners of transmission facilities.

Regional interests forming an RTO should consult with the states about what state roles best fit the agencies' authorities and preferences and the organizational form of the RTO. This role could vary from state to state within an RTO. Therefore, this Rule takes a flexible approach that allows states to play appropriate roles in RTO matters, consistent with this Commission's exclusive responsibilities and authorities under the FPA.

We note that we have discussed the role of states for particular RTO functions elsewhere in this Final Rule. Regarding RTO formation, the Background discussion above discusses the role that several states played in creating many of the existing ISOs. It also describes our initial consultations with state regulators on RTO formation and our roles in FPA section 202(a) implementation; in those consultations we offered to continue the RTO dialogue with states in the future. The form of consultation to be used should be decided based on the issues and the region so we will not endorse or reject here any particular form of collaboration. However, in the Collaborative Process discussion below, we set out our plans to invite states and others to work with us to foster RTO formation beginning early next year.

In our discussion above of the Independence characteristic, we discuss the role of state agencies in governance, making the point that states will play a key role in RTO formation and development but declining to specify generically a state's role in governance. Also, in our discussion above of the RTO Planning and Expansion function we recognize the exclusive authority of state and local governments and regulatory agencies over the siting of transmission facilities, and we include in our regulations the standard that an RTO must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities.

8. Accounting Issues

Although not discussed in the NOPR, EEI commented on some accounting aspects of RTOs. It urges the Commission to address two primary accounting issues for RTOs: (1) The need to revise the Uniform System of Accounts (USofA) and related reports to reflect new RTO and other unbundled rate structures; and (2) the ability of RTOs to use regulatory accounting.

a. Revision of the Uniform System of Accounts

Comments. EEI contends that because the Commission's USofA was developed when utilities' products were bundled and fully regulated, it needs to be revised to support the Commission's adopted policies and this proposed rule. EEI believes that with unbundling of rates, the USofA will need to be revised to reflect, among other things,[718] cost functionalization (*e.g.,* by generation, transmission, distribution, etc.). EEI also believes that the Commission should specifically address the accounting to be used for RTO reporting purposes, as the current USofA was not designed for use by RTOs. EEI states that it is very willing to work with the Commission's staff to address the specific changes that should be made to the USofA.

Commission Conclusion. The Final Rule permits the various regions to select different organizational forms for RTOs. Our open architecture structure for RTOs permits applicants to select the business organization best suited to the needs of its members and RTO participants. It would therefore be difficult to prescribe in this proceeding specific changes to our existing USofA that would accommodate the needs of all RTOs.

We believe a better course at this juncture would be to require RTOs to conform their accounting to our USofA (as have ISOs) and to submit questions of doubtful interpretation to the Commission for individual or generic rulings on particular transactions, events and circumstances.

However, we agree with EEI's observation that unbundling of utility services, and other changes in the industry require the Commission to re-examine its existing accounting and related reporting requirements. This is true not only for the new types of utilities that have emerged in the industry such as ISOs, PXs and RTOs,

[718] Another significant area cited is whether the Commission should modify its original cost accounting requirements for property acquisitions to conform with the evolving fair value requirements of the Financial Accounting Standards Board (FASB). *See* Appendix I to EEI Comments at 11.

but also for traditional public utilities. The Commission staff has been and will continue to meet with EEI and others, and will continue its efforts to address the specific changes that may be needed as the industry restructures.

b. Ability to Use Special Accounting

Comments. EEI asks the Commission to consider the impact of its actions on the ability of RTOs to use the special accounting rules applicable to cost-based rate-regulated entities.[719] EEI believes that the ability to use regulated accounting would be advantageous to RTOs and viewed favorably by the investment community.[720] EEI urges the Commission to structure alternative ratemaking methods (*e.g.,* price and revenue caps, incentive-based rates and price indexing) to allow RTOs to continue to use the special accounting of SFAS 71. In this regard, EEI believes that if the Commission decides it is advantageous to stimulate the establishment of RTOs by ensuring that all start-up costs are ultimately recovered through FERC jurisdictional rates, it could issue ratemaking orders that defer expense recognition of these costs, and allow for future ratemaking recovery. Similarly, EEI urges the Commission to address the time frame over which software development costs could be recovered through rates and to allow utilities to defer expense recognition of such costs. To enhance cash flows from operations, EEI suggests that the Commission accelerate the amortization of all capitalized software costs. These actions, according to EEI, would likely be viewed favorably by the investment community.

Commission Conclusion. RTOs may propose and we are willing to consider alternative ratemaking methods including proposals to delay rate recovery of certain expenses. We will not prescribe any specific requirements at this time but allow RTOs to propose those methods which are appropriate for each RTO's facts and circumstances. In this regard, we intend to take a flexible regulatory approach toward approving RTO rate design proposals and strive to include adequate information in our rate orders on the appropriate accounting treatments.

9. Market Design Lessons

We expect that bid-based markets will be a central feature in many RTO proposals. To date, the Commission has analyzed and approved, with various modifications, bid-based market designs for four ISOs. The purpose of this section is to summarize the lessons learned from these real-world market experiments. The summary provided below is not intended to favor one market design over another, but is intended to assist RTOs in evaluating existing market designs and meeting the deadlines set forth in this rule.[721]

Cal ISO, PJM and ISO–NE have had operational experience with their respective market designs. For the most part the markets operated by these ISOs have functioned well, and they have not experienced many of the problems encountered in the bilateral markets in the Midwest and the Southeast.[722] However, each of the operational ISOs has encountered some market design problems that have resulted in unexpected or undesirable market outcomes.[723] These outcomes have led some ISOs to file many market design changes and requests for temporary remedies or protections until permanent design changes can be implemented.[724]

a. Multiple Product Markets

The bid-based markets that we have approved to date are premised on the assumption that acceptance of voluntary supply and demand bids which maximize overall net benefits will also maximize efficiency. Each approved ISO design employs some bid-based mechanism to ramp resources up and down to balance the system, manage congestion, and to supply some ancillary services. Employing bids that indicate a generator's willingness to be ramped down, ramped up, or placed in reserve is an economic way to balance the system, manage congestion and maintain appropriate reserves, both in real time and in any day-ahead markets. However, if more than one product is being sold in the same temporal market,[725] efficiency is maximized when arbitrage opportunities reflected in the bids are exhausted (*i.e.,* after the RTO's markets have cleared, no technically qualified market participant would have preferred to be in another of the RTO's markets). In addition, efficient bid-based markets elicit prices that are consistent with technical and cost requirements.[726] For example, a situation where generating units are paid more for not generating than for generating as has happened in ISO–NE and the Cal ISO may be an indication of an inefficient market.[727]

b. Physical Feasibility

Proper design of the market clearing procedures ensures that prices balance the supply and demand for energy, and all transactions, in the aggregate, are physically feasible with appropriate levels of reserves. Some market designs have allowed ISOs to accept schedules that have not been physically feasible (*e.g.,* Cal ISO), while other ISO market designs include mechanisms to ensure the physical feasibility of transactions (*e.g.,* the NY ISO and PJM). Some ISOs have encountered instances where transmission constraints have prevented the use of needed reserves,[728] and this is inconsistent with the operator's obligation to make certain that reserve requirements are met and that reserves, along with necessary transmission, are available to respond appropriately to contingencies.

[719] The special accounting rules are primarily contained in Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71). One of the primary accounting differences is the ability to defer expense recognition of an incurred cost if it is probable that the utility will recover that cost in future cost-based regulated rates.

[720] Conversely, according to EEI, the inability of an entity to use SFAS 71 accounting could have an adverse effect on earnings, which may be viewed unfavorably by investors. According to EEI, one example would be where the Commission approves a rate levelization plan (*e.g.,* under capital lease transactions) under which rate recovery of certain costs would be deferred until future years. If a utility could not defer expense recognition of such costs, earnings would be depressed in the early years of the levelization plan.

[721] The Commission has already given considerable guidance on numerous market design issues in a number of orders. *See* Pennsylvania-New Jersey-Maryland Interconnection, L.L.C., 81 FERC ¶ 61,257 (1997); Central Hudson Gas & Electric Corp., *et al.* 86 FERC ¶ 61,062 (1999); New England Power Pool, *et al.* 87 FERC ¶ 61,045 (1999); AES Redondo Beach, *et al.,* 87 FERC] 61,208 (1999).

[722] *See* Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998 (September 28, 1998).

[723] The NY ISO has had little operational experience with the particulars of its markets design.

[724] *See* New England Power Pool, *et al.,* 87 FERC ¶ 61,055 (1999); AES Redondo Beach, *et al.,* 87 FERC 61,208 (1999); New York Independent System Operator, Inc. *et al.,* 88 FERC ¶ 61,228 (1999).

[725] For example, energy and operating reserve products may be offered in real-time.

[726] One would expect that services with more stringent technical requirements ordinarily have higher costs for providing those services. The prices of these services should reflect the costs. For example, spinning reserves have more stringent requirements and would be expected to command a higher price than non-spinning reserves.

[727] *See* Report of the Market Surveillance Committee of the California Independent System Operator, October 18, 1999 (MSC October Report). Both ISOs have seen prices for services such as non-spinning reserve products, which do not require a unit to be running, higher than the energy price. Also, according to the Market Surveillance Committee (MSC) of the Cal ISO, market participants have an incentive to submit schedules that will cause congestion so that their units can be called upon to relieve the congestion and receive payments for not generating that are greater than payments received for generating.

[728] *See* MSC October Report, at 67, 74–75.

c. Access to Real-Time Balancing Market

Real-time balancing refers to the moment-to-moment matching of loads and generation on a system-wide basis. Real-time balancing is usually achieved through the direct control of select generators (and, in some cases, loads) that increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator. Over the last several years, the Commission has seen an increasing use by system operators of market mechanisms that rely on bids from generators to achieve, overall, real-time balancing. In order to maintain system balance, the operator also manages congestion while maintaining the appropriate level of reserves. It is expected that any RTO balancing markets will be available to all grid users, *i.e.,* including individual grid users that engage in bilateral transactions. The fact that the overall system must be in balance moment-to-moment does not mean that there must be a moment-to-moment balance between the specific load and resources involved in individual bilateral transactions. Making a real-time balancing market available to all grid users ensures that all users are treated equally for purposes of settling their individual imbalances. The four operating ISOs approved by the Commission already operate such markets.

d. Market Participation

Markets are most efficient when generators and loads, whether internal or external to the RTO, are allowed full and flexible participation in the markets. While generators and loads have the option to choose between participating in any RTO-facilitated markets or other markets, the RTO must have generation and ancillary service quantity information, and any necessary technical information, from self-schedulers in order to balance the system and ensure reliability. This allows bilateral and forward financial markets and independent PX markets to co-exist and complement RTO physical markets. Participants that self-schedule would be expected to pay for the costs that they impose on the physical system at market prices and be paid for the benefits that they supply to the physical system at market prices.[729]

Unnecessary constraints on the imports of services can lead to increases in price volatility due to thin markets.[730] Allowing exports will give generators flexibility to take advantage of opportunities outside of the RTO boundaries, while allowing load serving entities external to the RTO a chance to purchase services. Broadening market participation deepens the market and enhances overall efficiency.

e. Demand-Side Bidding

Existing ISO markets offer generators flexible participation, but they often do not offer customers demand-side bidding options. Demand-side bidding is desirable to the extent it is technically feasible, because without it, demand response decreases and market power is easier to exercise.[731] The availability of price responsive demand also reduces price volatility in the markets.

f. Bidding Rules

A market that provides the flexibility for all generators to bid a reasonable approximation of the costs they incur including start-up, minimum load, energy, and ramping costs will be efficient. Whether it is cost-effective to start up a generator and make it available for dispatch depends on the prices and scheduled quantities over the multiple hours and services for which the generator is committed, not on the prices in any single hour or for any single service. Allowing participants to bid these costs helps provide for a more efficient dispatch of generating units to meet load and other services, because it allows the start-up decisions underlying the dispatch schedules to be based on prices and quantities for a period greater than a single hour. Not permitting start-up and minimum load bids can reduce efficiency because the decision to start up and dispatch generators is made separately for each hour, resulting in start up decisions that can cause losses for generators. Also, when the start-up and minimum load bids are submitted along with minimum run and down times, generators are ensured that they will not be dispatched in a way that is physically damaging to the unit.

g. Transaction Costs and Risk

Transaction costs associated with participation in well functioning RTO markets should be low, and market participation should involve no unnecessary risks. For example, in sequentially clearing markets, bidders are exposed to the risk that they may be chosen in one of the markets that clears first, yet would have preferred to have been chosen in a market that cleared later. In order to hedge against such risks, bidders may undertake expensive and time consuming bid preparation strategies to decrease the likelihood that such profitable opportunities would be missed.

h. Price Recalculations

In some instances, it may be necessary to post prices on a preliminary basis while the final price calculations are verified. For example, in ISO–NE, the computer algorithms generate new dispatch points every five minutes, and preliminary market clearing prices are based on these dispatch algorithms. However, the actual dispatch instructions are issued manually. In circumstances where time does not permit all changes in dispatch to be communicated and effected through manual processes in a timely manner, the market clearing price resulting from the computer algorithm must be adjusted to reflect the actual dispatch in the hour.[732] While an RTO must ensure that the final market clearing prices are correct, market clearing procedures should minimize price recalculations. Also, any price recalculation should be done quickly. Otherwise, market participants could incur large transaction costs in attempts to hedge against such risk. Risk exposure can be further reduced if market participants can engage in bilateral transactions, or participate in other markets, to lock in prices prior to participating in the RTO-facilitated markets.

i. Multi-Settlement Markets

Multi-settlement markets may involve a day-ahead and real-time market. For real-time markets, prices are determined by real-time dispatch quantities, and deviations from day-ahead schedules are priced at the real-time price. When day-ahead schedules are financially binding, they are financial commitments subject to payments for deviations at the real-time price. If market participants adhere to day-ahead schedules, they need not participate in the real-time markets. If needed for reliability, bids need to be physically binding and may be subject to Commission-approved penalties for failure to adhere to the bid. Without financially binding commitments in the day-ahead market, the riskiness of market participation

[729] Costs and benefits associated with self-schedules are congestion costs created by the transaction or congestion relief that the transaction makes possible.

[730] Thin markets refers to a situation in which the amount bid into the market is either not enough to match demand, or just enough to match demand.

[731] The flexibility of demand-side bidding may be limited unless real-time meters are installed. Otherwise, demand-side bidding can simply take the form of interruptible load.

[732] *See* ISO New England, Internal Review of Operations, June 7–8, 1999, Report issued August 20, 1999. Electronic dispatch is under consideration in ISO–NE.

increases since the day-ahead bids could be changed before real-time dispatch. If bids for ancillary services are accepted, the accepted capacity must be physically ready to meet reliability commitments when called upon. The lack of a physical capacity commitment has been a problem in some ISOs.

j. Preventing Abusive Market Power

An efficient market design does not favor market participants that have the potential to exercise market power and minimizes the incentives for market participants to engage in abuse of market power. For example, since large players are more likely to cause market power problems, a market design that favors large players (*e.g.,* portfolio bidding[733]) may create an incentive for consolidation and resulting market power problems. Fewer restrictions on imports of services will help guard against thin markets, which in turn will help mitigate market power. ISO's have experienced problems with thin markets, and easing restrictions on imports should help.[734] Also, artificially segmenting a product market into separate geographic markets for the same product can also create additional price volatility and opportunities for the exercise of market power.[735]

If market participants are allowed to submit bids which can then be changed before financial settlements are completed, these non-binding bids can be used as a signaling device to facilitate collusive behavior.

k. Market Information and Market Monitoring

One property of an efficient market has market clearing prices and quantities being made available immediately. This information enables market participants and potential future market participants to assess the market and plan their businesses efficiently. It will also allow market participants to spot errors in the market clearing process and get them corrected.

Disclosure of individual bids could be made eventually, but not immediately. Such disclosures will allow detection of market design and implementation flaws, and allow study of the market by independent analysts and market participants. It may lead to the exposure of the exercise of market power. To detect the withholding of capacity, a simple screen is to provide the output, reserve quantities, and maximum capacity of each generator. Immediate disclosure of individual bids is undesirable because it might facilitate collusion by the market participants. It also might affect the bids of market participants who wish to keep their costs confidential. However, after six months or a year, the information on individual bids has essentially no value for collusion and discloses little new information about any bidder's current costs. Nonetheless, the information's value for market monitoring remains high.[736]

l. Prices and Cost Averaging

Market designs that base prices on the averaging or socialization of costs,[737] may distort consumption, production, and investment decisions and ultimately lead to economically inefficient outcomes. Where possible and cost effective, cost causality principles can be used to price services and eliminate averaging.[738]

For example, in some congestion management mechanisms, the cost of alleviating congestion is spread over all loads. This scheme could have some generators creating monetary benefits for other generators. In addition, it could lead to over-consumption of power by some loads and under-consumption by other loads. Moreover, such averaging mechanisms for congestion management do not send the correct price signals for the location of new generation, thus leading to problems with long-term implications.[739]

Moreover, if pass-throughs or uplift charges are paid by all load to ensure bid-cost recovery, as in some approved ISO market designs, it may be appropriate to couple these pricing mechanisms with incentive mechanisms for the RTO to control them.

I. Collaborative Process

The Commission proposed a regional collaborative process to facilitate the creation of RTOs. State commissions had encouraged the Commission to sponsor activities in each region of the country that will bring together representatives of public and private electric utilities, state regulators, consumer groups, representatives from Canada or Mexico, as appropriate, and any other interested parties that need to be part of such a process. The Commission proposed that regional workshops be held after the Final Rule is issued to determine what, if any, impediments exist to the formation of RTOs in a particular region and how the Commission staff could help to overcome those impediments. Staff resources that will be available for the collaborative process include technical staff, dispute resolution staff, and any other staff assistance that would be beneficial.

Comments. Almost all commenters support the Commission's collaborative proposal. Of the 49 comments that addressed this issue, 47 are generally supportive. These commenters include a number of state commissions.[740] In addition, NARUC supports the continuation of a ''dynamic process requiring continuing dialogue between FERC and the states.'' A number of public power entities also support the process.[741] Numerous Canadian entities also filed comments regarding the usefulness of a collaborative process for the international aspects of RTO formation.[742]

Only Florida Commission and CP&L are not fully supportive. Florida Commission suggests that FERC collaboration will not work in Florida but may work in other regions of the country. CP&L is not supportive because the collaborative process could be used by the Commission ''as a means of forcing utilities to develop RTO proposals on the Commission's timetable'' which results in the Commission ''being disingenuous when it describes its RTO policy as 'voluntary'.'' Otherwise, CP&L believes the conferences will only serve as an opportunity for participants to ''posture'' and that limited Commission resources should not be used for

[733] Portfolio bidding refers to bids that aggregate all generating units under the same ownership. This is in contrast to generation owners bidding in each unit separately.

[734] Report of the Market Surveillance Committee of the California Independent System Operator, August 19, 1998 at 35–36 (MSC August Report).

[735] The Cal ISO at one time segmented their product markets into separate geographic markets that corresponded to the defined congestion zones even when no congestion existed. It has since reformed this practice. *See* MSC August Report, at 32–33.

[736] The Commission approved the disclosure of bid information in the following orders. *See* PJM Interconnection, L.L.C., 86 FERC ¶ 61,247 at 61,890, *order on reh'g,* 88 FERC ¶ 61,274 (1999); Central Hudson Gas & Electric Corp. *et al.* 86 FERC ¶ 61,062 at 61,204, *order on reh'g,* 88 FERC ¶ 61,138 (1999).

[737] Socialization of costs means that costs that could be assigned to a particular market participant(s) are instead spread over all participants regardless of whether or not they caused the costs.

[738] While it is desirable from an efficiency standpoint to eliminate the averaging of costs, the costs associated with calculating cost causation in some instances could be shown to outweigh the benefits of eliminating averaging.

[739] MSC October Report, at 112.

[740] *See, e.g.,* Nine Commissions, Illinois Commission, Indiana Commission, Michigan Commission, Montana Commission, Nevada Commission, South Carolina Commission, Wisconsin Commission and Wyoming Commission.

[741] *See, e.g.,* APPA, NRECA, CMUA, SRP, Snohomish, Seattle, RUS, East Texas Cooperatives, IMEA, and Arkansas Cities.

[742] *See, e.g.,* Powerex, BC Hydro and Canada DNR.

meetings that ''are not likely to produce positive results.''

Specific comments about the collaborative process address three basic issues: inclusiveness, process and procedures, and outcomes.

Inclusiveness. The NOPR stated that ''the Commission expects public utilities and non-public utilities, in coordination with appropriate state officials, and affected interest groups in a region to fully participate in working to develop an RTO.'' It further stated that the regional public workshops will be convened in cooperation with the affected state officials and that transmission owners and operators will be invited.

Many commenters advocate an open collaborative process that would include a full complement of participants. They suggest that the regional meetings include representatives of all stakeholders, for-profit transmission companies, not-for-profit transmission entities, state regulators, state legislators, state Governors, state energy officials, state and non-state consumer advocates, state economic and environmental regulators, environmental action interests and public power/municipals. Some commenters indicate that in certain regional efforts to form an RTO, the deliberations have excluded key interests and, as a result, the outcomes were not widely supported. For example, PJM/NEPOOL Customers note with respect to the PJM formation process that ''[O]nly after all stakeholders were included in organizational discussions was true progress made toward implementing an ISO that adequately addresses all parties' needs.'' PNGC states that ''[I]f other users do not have a seat at the table while merchant functions do, obviously a level playing field is not created.'' New Orleans cites Entergy's ''failure to even attempt to build a regional consensus concerning its transco as a reason that inclusive regional conferences are needed.''

Process and Procedures. Commenters raise a number of questions regarding the collaborative process and specifically with respect to the regional public workshops. Many commenters support the use/availability of the Commission's Dispute Resolution Service (DRS) staff or the use of outside facilitators. Some commenters request that the Commission clarify that the meetings will be open meetings that can be attended by any person. Several commenters urge the Commission to take the cost and travel time to attend meetings into account in planning the regional public workshops. Some specific locations are suggested for sites for the regional workshops: New Orleans, Minneapolis/St. Paul, and Seattle or Portland.

Several commenters suggest that the collaborative process begin prior to spring 2000 in at least one region of the country—the Upper Midwest. Commenters suggest that there is no need to wait and that the region would benefit by immediate assistance from Commission staff as described in the NOPR.

Some commenters ask the Commission to be mindful that the number of regional meetings scheduled may not only be costly but unproductive as well. Two commenters specifically say that we must not allow the ''death by meetings'' syndrome to be realized. Some interests may want to stall RTO formation by promoting an ''endless'' series of meetings that are not productive but are designed to ''preserve the status quo.'' A few commenters suggest that the role of Commission staff at the regional events should not be that of meeting referee but primarily to provide policy guidance on key RTO issues and proposals. NRECA proposes the creation of several Commission staff teams to ''facilitate and informally monitor each RTO formation process'' and provide ''neutral guidance'' in the regions. Some commenters ask that the Commission establish procedural rules in writing in advance of the regional workshops so that all parties will know and understand the rules prior to the meetings. Some commenters also request that all reports, information and data produced for the meetings be readily available to all participants.

Outcomes. The Project Groups suggest that the Commission should ''clearly delineate the substantive results expected'' from the collaborative process. They suggest that collaboration progress reports be filed with the Commission and that ''work products'' be required, including: (1) Identification of RTO boundaries; (2) a list of all transmission owners and facilities in the region; (3) a draft operating agreement; (4) a draft governance structure and bylaws; (5) proposed operating protocols; (6) a proposed budget/financial structure; (7) a draft tariff; and (8) how the proposals meet the Commission's guidelines, including a timetable.

Commission Conclusion. A key element of this Final Rule is our commitment to the use of the collaborative process to assist in the voluntary formation of RTOs. By collaborative process, we mean a process whereby transmission owners, market participants, interest groups, and governmental officials can attempt to reach mutual agreement on how best to establish RTOs in their respective regions. We reiterate our commitment of Commission staff resources, to the extent possible, to assist parties in developing RTO proposals.

We are encouraged that state Commissions, public utilities, public power entities and cooperative utilities, power marketing interests, and consumer and environmental groups support the use of a collaborative process. We are further encouraged that efforts to develop RTOs continue in the West and Midwest, and that other areas are reviewing the potential benefits of RTOs in their respective areas. We believe that this represents a growing recognition throughout the nation that RTOs will improve competition in electric markets and enhance the reliability of the nation's electric grid.

We welcome participation in the RTO collaborative process by our sovereign neighbors, Canada and Mexico. We believe that it is in our mutual best interest to have electricity flow efficiently and economically across our international boundaries. We pledge to continue to work cooperatively with officials from Canada and Mexico to encourage the operation and improvement of an international electric system that benefits all consumers.

The Commission believes that the collaborative process must accommodate the fact that different regions of the country are in different stages of RTO formation and must be flexible enough to allow for these differences. Therefore, we will initiate the collaborative process with a series of five workshops in the Spring of 2000. The primary objective of each workshop will be to develop a consensus agreement by regional participants establishing a strategic process and a schedule for any further collaboration. The appropriate collaboration process will depend on whether the region is considering formation of an ISO, transco, or other form of RTO. To achieve this objective, participants will share information about the status of RTOs or RTO proposals in the region, identify impediments to RTO formation in the area, explore which process(es) could most expeditiously advance agreements on RTO formation, and determine what role(s), if any, Commission staff should play in advancing discussions in each region. One result of these discussions may be regional decisions that more than one RTO would be appropriate in the area encompassed by participants at the workshop. Therefore, the collaborative processes that follow the various workshops may differ significantly. This includes possible variations in the role that will be played by Commission staff in each RTO formation effort.

The Commission believes that regional workshops in the Spring of 2000 will expedite the RTO formation process. In selecting locations for the initial Spring 2000 workshops, we recognize trends in the broader regionalization of the nation's electric system. We also consider the evolving electric markets as well as the configuration of the regional grid. We emphasize that the selection of locations for initial workshops is not to indicate a preference for specific RTO boundaries, but to provide convenient workshop locations. With these considerations in mind, we designate the following workshop locations. Parties may attend more than one regional workshop. We expect all transmission owners to attend at least one workshop.

Workshops will be held in the following cities in February, March or April, 2000:

1. Philadelphia, Pennsylvania
2. Cincinnati, Ohio
3. Atlanta, Georgia
4. Kansas City, Missouri
5. Las Vegas, Nevada

Workshops are expected to last for two days. Additional information about the regional workshops will be provided in January 2000.

At the request of parties, the Commission staff may play a role in the formation of RTOs. Commission staff will convene the regional RTO workshops and provide policy and technical guidance consistent with this rule. The Commission will supply meeting space for the five initial Spring 2000 workshops. Regional participants are expected to bear the costs of collaborative meetings after the initial five workshops. Commission staff time and staff travel expenses will be provided as resources allow.

We believe that it is critical to make the Spring 2000 Workshop phase of the collaborative process open to all interested parties. In order to promote an open process, we will provide public notice of Spring 2000 Workshop events to allow all interested parties to attend. We shall also make available agendas and procedural rules to all parties in advance of the regional workshops. Agendas may vary from one workshop to another.

The Spring 2000 Workshops represent the initial step of the collaborative process. We expect that other meetings will be convened following the workshops by parties in each region to bring the parties together to form an RTO in each region. Commission staff may also convene additional meetings if this would help RTO formation. The post-workshop meetings of parties in regions may be held with or without Commission staff participation. We will make available the Commission's Alternative Dispute Resolution staff upon the request of an RTO group in formation. At the request of such a group, independent private professional facilitation services may be arranged by Commission staff and must be sponsored by the parties within the region. As needed and requested by parties forming an RTO in a region, Commission staff members will be available to act as settlement judges, mediators, facilitators or observers.

We believe that the best interests of the nation's electric consumers will be served by the formation of RTOs. Therefore, we encourage parties to establish strategic schedules at the Spring 2000 Workshops and to convene subsequent meetings with the goal of forming an RTO expeditiously. Commission staff will monitor progress with respect to the results or outcomes in each region.

We expect that, following the initial Commission-sponsored workshops, parties in each region will work collaboratively to identify the appropriate RTO regions, identify all transmission owners and facilities in each region, and develop a timely application in accordance with the Final Rule.

We have designated James Apperson of the Commission Staff to serve as the collaborative process contact. He may be contacted at (202) 219–2962 with any questions or comments about the RTO collaborative process.

J. Implementation Issues

1. Filing Requirements

In the NOPR, the Commission proposed that all public utilities that own, operate or control interstate transmission facilities (except those already participating in a regional transmission entity in conformance with the eleven ISO principles enumerated in Order No. 888) must file with the Commission by October 15, 2000 either (1) a proposal to participate in an RTO that will be operational no later than December 15, 2001, or (2) an alternative filing describing efforts to participate in an RTO, obstacles to RTO participation, and any plans and timetable for future efforts.[743] For those public utilities that file an RTO proposal on or before October 15, 2000, we proposed to permit them to file a petition for a declaratory order asking whether a proposed transmission entity that would be operational by December 15, 2001, would qualify as an RTO, with a description of the organization and operational structure, a list of the intended participants of the institution, an explanation of how the institution would satisfy each of the RTO minimum characteristics and functions, and a commitment to submit necessary FPA section 203, 205 and 206 filings promptly after receiving the Commission's determination on the declaratory order petition. Finally, we proposed that the requirements not apply to a public utility that owns, operates or controls transmission that also is a member of an existing transmission entity that the Commission has found to be in conformance with the Order No. 888 eleven ISO principles; instead, each such public utility would be required to make a filing no later than January 15, 2001, that (1) explains the extent to which the transmission entity in which it participates meets the minimum characteristics and functions of an RTO; (2) proposes to modify the existing institution to become an RTO; or (3) explain efforts, obstacles and plans with respect to conforming to these characteristics and functions.

Comments. Most commenters responding on this issue oppose one or more aspects of the proposed filing requirements. For example, a number of public utilities and two state commissions argue that the October 15, 2000, filing requirement does not provide enough time. Southern Company contends that the proposed filing deadline requirement is likely to be counterproductive because it imposes an artificial deadline that may interfere with regional discussions. Moreover, once established, a prematurely formed RTO may itself prove to be an obstacle to more effective transmission organizations. Southern Company also claims that the proposed mandatory filing requirements are inconsistent with a truly voluntary approach. If the requirement is retained, Southern Company suggests that the Commission clarify that the alternative filings will be treated as status reports and not be subject to deficiency orders or otherwise lead to proceedings in which punitive measures might be taken, because any consideration or use of penalties seriously undermines the Commission commitment to the voluntary nature of RTOs.

Wyoming Commission recommends that the deadlines not be made

[743] FERC Stats. & Regs ¶ 32,541 at 33,761–63.

mandatory in any way in the Final Rule because RTO formation is supposed to be voluntary. Since it is unclear as to what happens to those entities who file an explanation as to why they did not join an RTO, Wyoming Commission urges the Commission to defer to each region's process and timetable in developing an RTO and acknowledge that not all regions are processing at the same pace. It recommends that the Commission convert the October 15, 2000, deadline into a milepost for reporting RTO development.

CP&L submits that the time frame is unrealistic because it contemplates that new RTOs can be developed, approved by the Commission, set up, and begin operation in less than two years. Experience has shown that almost every RTO to date has taken at least four years to go through that process. Therefore, the Commission should modify the filing requirements to simply require informational filings on the status of RTO development.

Sierra Pacific is concerned about insufficient time being allowed for transcos to form. It points out that the precedent regarding ISOs is much more well-developed than that regarding transcos. The certainty surrounding ISOs makes them more attractive particularly when a decision to form the entity must be made relatively quickly to meet the proposed October 15, 2000, filing date. To lessen the incentive to rush to join an ISO, Sierra Pacific suggests that: (1) The date for filing an RTO proposal should be extended to June 15, 2002; (2) the Commission permit transition mechanisms that will allow transmission owners to eventually join transcos; and (3) the Commission not require participation in an ISO to become a trap from which a transmission owner cannot extricate itself. ComEd provides supporting arguments, noting that where divestiture of transmission assets is involved to form transcos, the necessary transition period will largely be dictated by the sheer complexity—legal, financial (bonds and mortgage), real estate (titles/easements), taxation—of separating a designated portion of any electric utility that has historically been a vertically integrated utility.

Based on its experience with the Midwest ISO formation process, Kentucky Commission also argues that the proposed date to join an RTO or respond with reasons for not joining is too short. It points out that, if the Commission completes the Final Rule by the end of 1999, transmission owners will have less than one year to make a final decision on participation. Kentucky Commission urges the Commission to give transmission owning utilities additional time to look into joining an RTO, so that RTOs are not pushed so quickly that the best model fails to materialize as a result of market evolution that remains underway. South Carolina Commission and Big Rivers share the concern that the proposed timeframe is too ambitious, given the complexity of RTO related matters and the need to reach some level of consensus among those with vested interests.

Several commenters noted that meeting the October 15, 2000, filing requirement will depend on the Commission's standard of review of those filings. For example, TDU Systems observes that the proposed filing requirements have no teeth. TDU Systems contends that a public utility that decides not to participate in an RTO can make an alternative filing setting out the reasons why it is not doing so and what plans it has to work towards participation. In TDU Systems' view, while the proposed regulations are consistent with voluntary participation, they are inconsistent with full and effective participation in RTOs. TDU Systems counsels that the Commission should resist calls to water down the RTO regulations even more, so as to treat alternative filings as mere status reports that allow transmission monopolists to hold on to their monopolies.

Duke submits that if the Commission is willing to accept valid, well-justified explanations as to why a utility has not become an RTO member, the October 15, 2000, filing requirement is reasonable, noting that until state commission review of restructuring and RTOs is completed, it may be premature for a utility to commit resources to RTO membership. Similarly, Iowa Board suggests that, where transmission providers are making legitimate progress, a report to that effect should not be received with automatic disfavor. Alternative filings and legitimate progress reports should be given equal validity with definitive proposal filings.

A few commenters explicitly support the October 15, 2000, filing requirements. For example, SRP believes it to be an acceptable balance between mandated participation and the status quo. PJM/NEPOOL Customers also support the filing by a date certain because this would expedite the collaborative process and ensure that no entity can effectively block RTO formation by engaging in inappropriate negotiation tactics. And Oglethorpe views the October 15, 2000, time frame as necessary to assure the timely development of RTOs and help develop fully competitive efficient wholesale markets. Cinergy, noting that only after the Commission has had opportunity to review the October 15, 2000, filings will it be able to determine whether it should order participation in or reconfiguration of particular RTOs, suggests that by April 15, 2000, all public utilities be required to file a statement of position in which each utility identifies each state in which it owns transmission, and the RTO in which it is considering membership and its potential scope and configuration to the best of its knowledge.

A number of commenters address issues and treatments relating to existing ISOs. Virtually all of the existing ISOs assert that the Commission should allow the previously Approved ISOs to continue to develop without undue interference in order to foster experimentation and testing of proposals.[744] Cal ISO argues that the Commission should find that existing regional entities generally meet the RTO criteria and that the Commission should confirm its determination not to require substantial changes in approved ISOs that would undermine difficult to reach consensus on critical issues. Similarly, the Pennsylvania and New York Commissions recommend that FERC grandfather the existing ISOs that meet the RTO characteristics and functions. The Pennsylvania Commission states that it does not want to tinker with the inner workings of PJM, nor constantly revisit and revise operations and functions. The New York Commission is concerned that the New York ISO tariff may have to incorporate the ''ordinary negligence'' liability and indemnification provisions set forth in the pro forma tariff if the ISO becomes qualified as an RTO, and that this will increase the ISO's exposure to litigation. The South Carolina Commission supports NARUC's position urging the Commission to grandfather existing ISO boundaries that are satisfactory to the states. Similarly American Forest, CalPX and Mid-Atlantic Commissions want the Commission to respect existing ISOs.

Furthermore, PJM/NEPOOL Customers contend that their ISOs are in basic conformance with the minimum functions and characteristics. To the extent that any deficiencies are found, the ISOs should be allowed to engage in continued experimentation without interference from the Commission. The Wyoming Commission also fails to see why existing ISOs, already having gone through a rigorous approval process, should have to re-certify as RTOs.

[744] *See, e.g.,* NY ISO, Cal ISO, NYPP and ISO–NE.

Moreover, EEI notes that the Commission should weigh the incremental gains achieved through economies of scale, efficiency, and additional savings against the potential incremental costs of reorganization, new computer programming, infrastructure changes, and changes required to achieve effective communication and coordination. NYPP proposes that ISOs be allowed to evaluate the costs and benefits of forming an RTO after some years of market experience; hence, they oppose putting members of existing ISOs on the same time frame for compliance as non-members of ISOs/RTOs. United Illuminating recommends that the Commission continue to honor and not abrogate pricing arrangements of existing ISOs. United Illuminating also contends that, since existing ISO members have no opportunity to discriminate because they have turned control of their transmission over to their respective ISO, the Commission cannot generically abrogate existing ISO pricing arrangements pursuant to its FPA section 206 authority in this rulemaking. Central Maine offers that consolidating the PJM, New England and New York ISOs into a super-ISO will require costly expansion of telemetry, communication, and computer equipment, that it could result in a decrease in reliability, and that simple interregional coordination could accomplish the Commission's goals without consolidation.

A few non-ISO entities oppose any grandfathering of existing regional transmission organizations.[745] For example, New Orleans argues that the Commission should not exempt existing regional transmission entities from requirements of RTO formation because only through universal application will all regions of the country receive the benefits of open and competitive electric markets. H.Q. Energy Services suggests that a larger territory, such as the combined territory served by the existing New York, PJM and New England ISOs, would be more effective than the NY ISO standing alone. PG&E counsels that freezing the existing ISO structures in place would not serve reliability or the marketplace and would be inconsistent with the open architecture requirement. It believes that the Commission has struck an appropriate balance imposing a reporting requirement on existing ISOs.

Most commenters agree that existing operational transmission entities should gradually evolve toward RTOs during a transition period, rather than making immediate and drastic changes.[746] According to SMUD, a transition period will enable customers to avoid bearing unnecessary costs.

A few commenters address the specific filing requirements outlined in the NOPR. The New York Commission asserts that the NY ISO should not have to make a filing because it possesses the requirements of an RTO. In addition, the Cal ISO argues that existing entities, rather than individual public utilities, should be responsible for the RTO filing requirements. Likewise, PJM suggests that existing ISOs report to the Commission prior to any report by its public utility members, as the existing ISO is in a better position to provide the Commission with the most accurate information by which to evaluate whether the ISO satisfies the minimum characteristics and functions for RTOs. PJM suggests that existing ISOs and existing transmission entities file reports no later than December 31, 2000, explaining whether they satisfy the Commission's requirements for RTOs and identifying any additional authority they may require for this purpose. On the other hand, EPSA welcomes the proposal requiring a showing of how the existing transmission institutions meet the minimum characteristics and functions by January 15, 2001, as a way to help address and solve continuing discrimination within current ISOs and address whether these institutions should be combined into larger groupings. Similarly, NYC wants the NY ISO's January 15, 2001, filing to demonstrate how its efforts to improve regional cooperation will overcome the institutional impediments that have contributed to the city's load pocket condition.

Finally, commenters raise a number of miscellaneous issues: Puget questions whether there will be negative implications for any entity the choose to cease participation in an RTO; DOE points out that RTOs may need to fund pensions for transferred employees, and existing transmission providers may need to fund early retirements or other compensation for displaced employees; UMPA recommends that recourse to the Commission in a *de novo* capacity must be part of all RTO dispute resolution procedures; and Indiana Commission, Snohomish and Midwest ISO express concern about how the Commission intends to handle multiple RTO proposals covering approximately the same region.

Commission Conclusion. The Commission will adopt the NOPR proposal requiring that all public utilities that own, operate or control interstate transmission facilities (except those already participating in an approved regional transmission entity) file by October 15, 2000, either a proposal to participate in an RTO or an alternative filing describing efforts and plans to participate in an RTO. As proposed initially, we will consider a petition for declaratory order setting forth the items listed in section 35.34(d)(3) as a proposal to participate in an RTO.

We believe that the October 15, 2000, date for filing proposals is realistic. It is not overly aggressive, given the amount of guidance we have provided in this Rule and the amount of flexibility we are permitting in how to satisfy the minimum characteristics and functions. In addition, the collaborative process that we are promoting in this Rule will provide an opportunity for all interested parties with their varied interests to resolve many of their differences, in advance, and reach consensus on the RTO solution that best fits the overall needs of their respective region. The October 15, 2000, filing date should help keep the parties focused and accelerate their efforts toward selecting an appropriate RTO model.

The October 15, 2000, date for filing is also reasonable because, even if a public utility is unable to file an RTO proposal at that time, we are permitting the public utility to make an alternative filing reporting on the status of pertinent RTO formation and development, the obstacles that have prevented the filing of an appropriate RTO proposal, and any of the public utility's plans and timetable for future efforts directed toward RTO formation and participation.[747] Given the importance that the Commission places on RTO development, it is important for us to understand no later than October 15, 2000 just how much progress the industry is making on forming RTOs. If the October 15, 2000, filings reveal obstacles that prevent serious progress toward RTO formation are reported for a given region, we will be able to act early enough to provide guidance on what steps we think are appropriate to help address the obstacles (*e.g.*, further collaborative efforts). And where serious regional progress is reported, but more time is requested in connection with meeting a particular RTO requirement, we will be able to act early enough to try to accommodate the local needs,

[745] *E.g.,* Illinois Commission, New Orleans, SMUD and Turlock.

[746] *See, e.g.,* SMUD, PJM/NEPOOL Customers, NYPP, Cal DWR, MEAG, American Forest and Central Maine.

[747] Of course, these reports may be filed prior to October 15, 2000.

complications and complexities that the particular region faces.

Some concern has been expressed that the October 15, 2000, filing date is too short to allow transcos to form because of the inherent legal, financial, real estate and taxation complexities associated with the transfer of ownership of the affected transmission assets. We are not proposing that the restructuring be completed by October 15, only that a proposal be filed, or an alternative filing as described in this Rule. Moreover, we take note of the fact that other forms of major corporate restructuring, including mergers, have proceeded from initial idea to formal proposal in a shorter time when the motivation is sufficient. Therefore, we do not think the time allowed is too short for transco proposals.

We also reaffirm the proposed January 15, 2001, filing date for transmitting public utility members of an existing approved transmission entity to address the extent to which that entity conforms to the minimum characteristics and functions of an RTO, any plans to make it conform, and any obstacles to full conformance with our Final Rule. We note that RTOs will not be ''starting from scratch.'' There is significant information available about both the good and bad experiences with ISOs, and this information should help RTOs meet this filing deadline.

While we are allowing a later filing date for existing transmission institutions to file (January 15, 2001, versus October 15, 2000), we do this because, in general, the transmission owners in those regions have already made substantial progress in establishing regional entities. Nonetheless, the Commission needs to know, for all regions, including those covered by existing approved transmission institutions, the extent of progress toward formation of fully functional RTOs. To the extent that an existing ISO, for example, is less than adequate with regard to one of the necessary characteristics or functions, we would expect the existing institution to be working on a plan of action to make the remedial improvements that are required to bring it into conformance with the Final Rule.

In sum, we continue to believe that the October 15, 2000, and January 15, 2001, filing dates represent an acceptable balance between the need to move toward RTOs as soon at possible and the need for sufficient time for transmission owners and market participants to develop proposals.

2. Deadline for RTO Operation

The Commission proposed that all public utilities participate in an RTO that will be operational by December 15, 2001. In addition, we contemplated implementation of the congestion management function within one year after startup (by December 15, 2002), and implementation of inter-regional parallel path flow coordination and transmission planning and expansion functions within three years after startup (by December 15, 2004).

Comments. Most commenters suggest the December 15, 2001, deadline should be changed to a later date or that the Commission provide greater flexibility in meeting the deadline. On the other hand, Oregon Commission explicitly favors the December 15, 2001, deadline, arguing that the time line is designed in stages so that the easiest requirements come earliest. EPSA fears that further delay of any of the operational deadlines for any of the required RTO functions (*i.e.*, for initial startup, congestion management, parallel path flow coordination, or transmission planning and expansion) will only encourage further debate and dialogue without driving the industry towards acceptable resolutions, and prolong the problems of residual discrimination and remaining market inefficiencies.

Two commenters propose an earlier deadline. PG&E contends that the transition period for RTOs to meet all requirements must be as short as possible—no more than one or two years to fully operational RTOs may be reasonable. Sithe similarly argues that, while the negotiations and proceedings associated with voluntarily RTOs can take years to complete, the California experience suggests that an RTO can be established quickly if a deadline exists. Sithe recommends that the Commission reconsider its time frame and do everything it can to hasten the process of putting in place RTOs with all minimum characteristics and functions. It observes that, as proposed in the NOPR, an RTO could defer for up to three years the filing of a plan for transmission planning and grid expansion. The details may not be finally approved by the Commission for at least another year such that a delay of over five years could result.

SRP and American Forest express concern about who will be responsible for building and paying for new transmission facilities until the RTO takes on this responsibility. In particular, SRP suggests that the Commission require each RTO filing to describe who will be responsible for financing and building transmission expansions during the interim.

Most commenters, however, view the proposed deadline as too aggressive, and recommend that it be eliminated or extended. CP&L views the operating deadline as arbitrary and capricious, and argues that the deadline will impose higher implementation costs and inefficiency that will not benefit the public or the industry. South Carolina Authority believes that to assume that a large group of stakeholders with diverse interests can somehow come together and agree on a particular RTO model and configuration by October 15, 2000 that is up and running by December 31, 2001, is unrealistic. East Kentucky suggests that the timetable be extended approximately two years. Montana Power encourages extension by one year because areas like the Pacific Northwest will probably need significant infrastructure to be developed or re-deployed and the 14 month time frame contemplated after RTO proposals are due on October 15, 2000, is not sufficient time.

A number of commenters favor a flexible approach and allowing provisional RTO status. Cinergy offers that, to overcome obstacles such as legal impediments to public power participation, alternative means of RTO participation be considered such as joint operations without the functional integration of public systems' facilities to allow them to control the private use of their systems. SERC generally concurs. Williams contends that not all RTOs will be able to develop at the same pace, and supports provisional RTO status with dates certain respecting those functions not able to be performed at startup.[748] SNWA recommends that, if necessary, a phase-in approach should be used in the implementation of an RTO to smooth the implementation process. Project Groups contends that, given the California experience, the cost of attempting to do everything at once is significant. Transmission ISO Participants urges flexibility for transmission owning members of exiting ISOs since the current structure represents an imperfect and probably unfinished agenda. EEI contends that the Commission should allow flexible timetables to establish RTOs that are transcos, contending that a vertically integrated utility that selects the option of moving transmission assets to a transco faces complex financial and tax issues. Nevada Commission urges the

[748] Note that a number of comments opposing deadlines are based on the difficulty of attaining specific RTO functions. These comments are also addressed in the sections regarding the specific functions.

Commission to clarify that there is no prohibition against forming interim organizations such as an independent system administrator until such time as a viable RTO for the region is formed. South Carolina Commission claims that each RTO proposal should be reviewed on a case-by-case basis for general adherence to the Commission's overall policy goals.

Indiana Commission cautions, however, that careful consideration should be given to what will be lost by the acceptance of an RTO ''lite.'' It argues that existing transmission entities may see little value in maintaining relatively high standards and could view the Commission acceptance of lower standards as an incentive to gravitate to lower standards. PG&E recommends the Commission grant waivers from its requirements only in limited cases and only for short durations. AEPCO, contends that there should be a reasonable basis for granting waivers, particularly for non-jurisdictional entities. In particular, a request for waiver should consider: (1) How much additional RTO transmission would result from inclusion of the facilities in an RTO; and (2) whether the RTO would be functional without inclusion of the entity's facilities. Sithe argues that care should be taken when considering whether to permit RTOs to go into effect without meeting functions and in granting waivers, and suggests that the Commission establish clear requirements for RTO approval, strictly scrutinize proposals, and not hesitate to reject inadequate proposals.

Commission Conclusion. We have decided to retain the originally proposed startup and other functional implementation deadlines (RTO startup by December 15, 2001, implementation of congestion management by December 15, 2002, and implementation of the parallel path flow coordination and transmission planning and expansion functions by December 15, 2004).

As a general proposition, we believe that, given the urgent needs of electricity markets as discussed elsewhere in our Final Rule, we have an obligation to promote RTO operation at the earliest feasible date. Even where a market may already be served by an ISO or other approved transmission entity, we are concerned that such market may remain hampered to the extent that the approved entity has yet to fully conform with our Final Rule.

In response to those who contend that December 15, 2001, is too ambitious for RTO start-up, we note several points. First, we, and the industry, now have had the benefit of the experience of the formation of five ISOs under Commission jurisdiction, an ISO in ERCOT, some international experience with regional transmission entities, and substantial discussion of the subject of regional transmission entities within the industry. While the timeframe we are suggesting for RTO formation may have been unrealistic several years ago, much has been learned since then which should facilitate more rapid formation.

Second, our Final Rule is providing substantial flexibility that should permit an RTO to satisfy the minimum characteristics and functions in a cost efficient manner. For example, we are not requiring control area consolidation; we are not requiring the establishment of a PX; we are allowing an RTO to meet its operational control obligation through indirect or hierarchical control arrangements via contractual agreements with the existing infrastructure such as transmission owners and control area operators; and we are allowing an RTO to satisfy its security coordinator functions through contractual arrangements with an external security coordinator, as long as it is independent. An acceptable RTO structure need not be a monolithic organization that requires an extended period of time to become fully set up so that it can directly ''push all of the buttons.'' Moreover, we are allowing a longer phase-in period for functions that may be more difficult to establish, such as congestion management, parallel path flow measures, and transmission planning and expansion.

With respect to the comments that question the December 15, 2002, deadline for implementing the congestion management function, we believe that lack of effective and market-oriented congestion management is a critical issue in the industry, and that it needs attention soon. We acknowledge that developing a sophisticated congestion management program can be an extremely complex and time consuming matter. However, implementation of economic approaches to congestion management by some of the approved ISOs shows the feasibility of these concepts where there is an institution to undertake the organization of this function over a large area.

Some say that transmission congestion is not a serious problem in their regions, and that they therefore should not be required to develop a complex congestion management plan within a short time-frame. We agree that an RTO should not have to expend large resources to address a problem that does not exist. However, we are concerned that an RTO fully analyze the extent to which transmission congestion does or could interfere with electricity sales in its region, and that it be prepared to address congestion if it becomes a more serious problem through changing markets. As markets become more competitive and the volume of discrete transaction increases, transmission congestion may become serious unless action is undertaken beforehand. Where transmission congestion is infrequent, this Rule does not preclude the establishment of relatively less complex forms of market-compatible congestion management such as generation redispatch protocols.

In sum, we think that the phased startup and other functional implementation deadlines are reasonable.

3. Commission Processing Procedures

The Commission recognized that RTO formation would be complicated by the requirements for Commission approval of transfer of control of jurisdictional facilities under FPA section 203 and Commission approval of RTO transmission rates, terms and conditions under FPA section 205. In the NOPR, the Commission requested comments on whether the Commission should provide expedited or streamlined processing procedures for RTO filings and asked for suggestions regarding how the Commission can further expedite and streamline procedures.[749]

Comments. Views on streamlined and expedited processing of RTO filings are mixed. Commenters that generally favor streamlining include Desert STAR and TEP, which suggests that filing requirements be kept simple and flexible.

A number of commenters offer specific suggestions for streamlining and expediting the process, including:

• Florida Commission believes that once an RTO or other structure has been agreed upon by a group of entities, the Commission should expedite all required processes in order to allow the participants to start implementing the agreed upon changes.

• Tallahassee recommends that the Commission should clarify that it is not revisiting the functional test for distinguishing transmission and distribution facilities addressed in Order No. 888.

• Entergy asserts that significant delay in obtaining Commission approvals will make it difficult for Entergy to institute a transco within the time-lines established by state restructuring laws in Arkansas and Texas. Providing clear rules on the

[749] FERC Stats. and Regs. ¶ 32,541 at 33,759.

required and permissible features of RTOs as the Commission did in its July 30, 1999 Declaratory Order for Entergy and providing clear standards on pricing policies will help. Entergy argues that the Commission should make explicit its willingness to consider requests for expedited approval when a showing is made that expedition is necessary, as it has done for California ISO.

• Trans-Elect notes that if a transfer of facilities cannot close under Section 203 until the related FPA section 205 proceeding is concluded, an expedited Section 205 filing must also take place. One way to do this is to waive an Initial Decision and set a date certain for the Commission's section 205 decision.

• PJM/NEPOOL Customers recommend that a standard RTO governance structure be adopted that allows participation by all stakeholder groups. It would expedite processing by requiring that any RTO filing demonstrate that all stakeholders were included in the formation process.

• SMUD recommends that the Final Rule require that RTOs be designed, developed and implemented in a manner that does not require numerous tariff amendments to remedy market ills that could be addressed prospectively or at a speed that does not dramatically increase RTO development costs.

On the other hand, some commenters urged the Commission to exercise caution regarding streamlining and expediting:

• East Texas Cooperatives observes that a poorly configured RTO can potentially be more harmful to the industry than the status quo, by allowing large transmission owners to dominate regional grid management, maintain pancaked rates and discriminate in allocating transmission revenue.

• Indiana Commission recommends that state commissions and other interested parties have full opportunity to thoroughly review, comment, and have an impact on the RTO proposals once they are filed with the Commission.

• Puget indicates that a negative implication of allowing streamlined filing and approval procedures for RTO participants is that regulatory burdens will be leveled against nonparticipants while those who join an RTO will be freed from what the Commission implicitly recognizes are unnecessary requirements. A truly voluntary system would not continue to impose unnecessary regulatory requirements on nonparticipants and there is no reason for the Commission to delay implementing these regulatory reforms now before a final decision is made regarding the wisdom or efficacy of RTOs, or to condition the implementation of such reforms on an entity's participation in an RTO.

• Duke contends that, given the size and complexity of the typical section 203 and 205 of the FPA filings, it is not clear that reducing the time that parties are granted to review such filings and provide initial comments may be appropriate. Nonetheless, the Commission should work to dismiss irrelevant issues used as leverage to extract concessions unrelated to RTO formation, it should consider use of less formal hearing procedures for issues that do not require discovery, and the Commission should limit the time period allowed for evidentiary hearings. Duke acknowledges that the effect of streamlined filing and approval procedures could be to reduce costs that would otherwise be born by market participants.

Commission Conclusion. While there is broad-based consensus for simplifying the Commission's RTO filing process and responding to RTO proposals expeditiously, we must maintain an appropriate balance between streamlining and expediting the filing and processing of RTO proposals and ensuring due process and the development of an adequate record. Given the amount of flexibility we have built into the Rule as to organizational structure, it is difficult to predict what issues will be raised by the RTO proposals and the degree of complexity raised by such issues. Accordingly, while the Commission has the goal of ensuring the rapid formation of RTOs, and will attempt to process each RTO proposal as expeditiously as possible, certain RTO proposals will take longer to analyze and review depending upon the complexity of the issues and the level of support among the affected parties. Therefore, in addition to the specific guidance provided elsewhere in this Rule, we provide further guidance and note the following factors which are intended to assist public utilities in streamlining their required filings and help expedite the processing of the RTO proposals.

One factor that should facilitate faster processing is that the Final Rule permits delayed implementation dates for various highly complex FPA section 205 related RTO provisions (congestion management by December 15, 2002, and parallel path flow coordination and transmission planning and expansion each by December 15, 2003). Therefore, initial RTO proposals need not contain the details for these provisions, but need only contain a commitment to complete the provision and a timetable for submitting appropriate future filings. Likewise, we need not act on those matters initially in our RTO orders.

Expeditious processing of an RTO submittal is more likely to occur if the RTO proposal is the result of a comprehensive and open collaborative process with widespread support from transmission owners, market participants, and affected state commissions. While we cannot pre-approve unopposed proposals, many of our potential concerns could be minimized to the extent the proposal has broad support.

Another potential streamlining measure is that public utilities are permitted to file RTO proposals jointly with other entities. For example, in the case of existing ISOs and other approved regional transmission entities, the regional entity may file on behalf of the individual public utilities. This will reduce the volume of submittals that must be developed by public utilities and be reviewed by the Commission.

We note that, with the exception of governance, experience gained from past ISO proceedings, will be directly transferable whether the form of RTO is an ISO or a transco. For transcos, as discussed elsewhere in the Final Rule, restrictions on ownership of transcos that we have adopted are designed to work in tandem with restrictions on governance in order to ensure adequate levels of independence.

We believe that RTO proposals that reflect the above factors, should allow the Commission to minimize the amount of time necessary to analyze and process the submittal. While the Commission cannot guarantee that we will be able to respond to every proposal within a pre-set period of time, we will make every reasonable effort to issue an initial order on an RTO proposal within 60 days,[750] after the comment period closes.[751] With respect to RTO proposals that present contested issues or problematic RTO provisions, we will make every effort to expedite

[750] We recognize that, while there is no statutory deadline to act on section 203 filings, there is a 60-day statutory clock requiring action on section 205 related filings within 60 days from the date of filing, in the absence of a proposed effective date extending beyond the 60-day time frame. However, in most instances, we expect that the RTO submittals will typically propose FPA section 205 effective dates that will be beyond the 60-day nominal clock.

[751] This proposed time frame refers to applications that are consistent with the guidance provided in this Rule and that provide all the necessary information. We further note that the Commission's review process will restart in the event that applicants modify their proposal or supplement the supporting information in their application.

consideration of the proposed RTO and we will continue to consider alternatives to formal procedures (*e.g., ADR procedures), where warranted, to avoid initiating a hearing.*

What the Commission has approved for ISO forms of governance can be used as models for governance of RTOs that are ISOs. Nothing in this Rule prohibits the types of independent governance structures we have approved to date. All of the ISOs approved to date, except one, have a two-tier form of governance wherein a non-stakeholder board at the top generally has final decision-making authority on most issues. Below this board are advisory groups or committees comprised of stakeholders that provide advice and may share some decision-making authority. With regard to the second-tier, the Commission has required that no one constituency in any group or committee be allowed to dominate the recommendation or decision-making process over the objection of the other classes, and that no one class holds veto power over the will of the remaining classes. The California ISO's governance structure is different. It has a single-tier hybrid decision-making board comprised of both stakeholders and non-stakeholders. No two classes can push through a decision over the objection of other classes, and no one class has veto power over the will of the remaining classes.

4. Other Implementation Issues

Commission Conclusion. An additional issue some commenters raised in connection with implementation concerns how the Commission intends to handle multiple RTO proposals that pertain to the same or overlapping regions. We expect that proper adherence to the collaborative process and the RTO scope and configuration factors we have identified, in the first instance, will bring order to the formation of RTOs such that the Commission will not need to step in and decide the matter of competing RTOs at the filing stage.

Several miscellaneous RTO implementation issues that were raised by some commenters concern the terms of withdrawal for members from an RTO, the RTO's funding of staff compensation in connection with transfers of personnel from other entities, and the Commission serving as a backstop for RTO's ADR processes. These matters, however, are best left to case-specific determinations in response to particular RTO proposals.

In response to those who argue for or against rejection or waiver in connection with less-than-fully-conforming RTO submittals, we believe the concepts of rejection and waiver are not appropriate. We have provided a significant degree of flexibility in the minimum characteristics and functions, and in many instances specifically allow for alternative ways to satisfy those characteristics and functions. Proposals that do not satisfy the minimum characteristics and functions will not be approved as RTOs. That does not mean that such a proposal would be summarily rejected; in fact, it may still be an improvement over the status quo as long as it is consistent with the FPA requirements. However, it may be questioned the extent to which entities that are not participating in RTOs have acted to eliminate the impediments to competition we have identified in this Final Rule.

IV. Environmental Statement

This section reviews and adopts the Environmental Assessment (EA) prepared by the Commission staff in connection with this Final Rule. It identifies the alternatives considered by the agency in reaching its decision; analyzes and considers whether and to what extent, if any, the chosen alternative—adoption of this Final Rule—affects the quality of the human environment; and states the Commission's decision.

Summary

The analysis compares generation and emission trends under the Final Rule to baseline trends without the Final Rule. The analysis indicates that the Final Rule will result in little generation change on a net national basis, but there may be shifts in regional generation. Economic benefits of the Final Rule can be realized with no significant, adverse environmental impacts. Further, the potential exists for environmental benefits to be realized, through the encouragement of newer, cleaner resources.

Discussion

A. Background

To further the policies and goals of the National Environmental Policy Act of 1969 (NEPA), Commission staff prepared an EA in order to examine potential impacts that could result from implementing the Commission's Rule, and to serve as the basis for considering whether the Final Rule will have significant impacts on the quality of the human environment. On May 14, 1999, the Commission issued a notice of intent to prepare an EA, and a request for comments on the scope of the issues that should be addressed in the EA. On July 8, 1999, a public scoping meeting was held at the Commission. On October 22, 1999, the Commission issued an EA, and invited interested parties to comment on the EA. Comments were due on November 22, 1999.

The Commission received two filed comments on the EA (NMA/WFA/CEED and Project Groups on behalf of multiple public interest groups). Specific comments are addressed in the relevant sections below.[752]

B. Scope of the Analysis

The EA examines potential environmental impacts that could result from implementing the Commission's Final Rule. The impacts are necessarily uncertain because they would be the product of changes in economic regulation that may alter the future behavior and perhaps the future structure of electricity supply markets. In turn, these behavioral and structural changes could lead to a different set of environmental conditions than would otherwise be the case. The analysis recognizes the uncertainty of the Rule's potential effects on future markets. It presents a systematic view of possible future market changes and assesses a range of possible responses to market changes, but should not be seen as predictive of specific market or environmental outcomes.

The EA addresses a broad range of potential economic changes that could result from the Rule. These impacts include changes in the mix of electric generating plants built in the future, shifts in the utilization of existing plants, and increases in interregional transmission. The analysis, therefore, includes major air pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury, and carbon dioxide associated with various types of generating plants and fuels. The EA addresses potential environmental impacts at national and regional levels.

Project Groups expressed concern that the EA does not retrospectively analyze the impacts of open access policies to date. As stated in 1.3.2 of the EA, we believe it is neither possible nor desirable to analyze such changes. Data collection lags, and the short period of time that has elapsed since the issuance of Order No. 888, would preclude us from drawing meaningful conclusions.

Project Groups also stated that economic impacts are not specifically reported in the EA, making it more difficult to evaluate the impacts of the

[752] As noted in the EA, a number of comments filed during scoping relate to matters outside the scope of the EA, and for the most part deal with policy issues that are addressed in the Rule.

Rule. We note, however, that the modeling and analysis conducted for the EA are the basis for the economic discussion contained in the Final Rule. These economic results do not provide a complete analysis of the potential economic impacts because the analysis considers only economic effects which may relate to operating decisions or new capacity, and thus may lead to environmental consequences. However, there are other economic benefits from competitive wholesale electric power markets which have little or no effect on the environment.

C. Analytic Approach

Because the impacts that could result from the rulemaking are uncertain, an analytic approach known as scenario analysis was used. In this approach, alternative views of the future are postulated and analyzed with and without the Final Rule. Potential environmental impacts are evaluated by comparing the analytic results of the scenarios. First, an analytic base case was developed. This base case relies on the assumption that the Commission would pursue current policy with respect to wholesale electric competition using existing rules and procedures, including case-by-case implementation of regional market arrangements.

Having established an appropriate base case, the EA analyzed future impacts assuming that the Rule is in effect. Staff adopted the assumption that the Final Rule, although voluntary, would result in the establishment of RTOs throughout the study area with the characteristics and functions set forth in the Final Rule. Three scenarios were developed to reflect a range of possible economic and environmental outcomes: Transmission Efficiency Scenario; Transmission/Generation Efficiency Scenario; New Entry Scenario.

D. Alternatives to the Rule

The primary alternative to the Final Rule is for the Commission to maintain the status quo, that is, to continue its existing open access policies. The result of this no-action alternative, without implementing the Final Rule, is that the Commission would effectuate an open transmission grid, but not address changes in the industry that have occurred since Order No. 888 was adopted. However, the no-action alternative describes what is likely to happen if the Commission takes no action over and beyond implementation of existing policies. Once this baseline is established to portray what is likely to happen in the electric industry during the study period, the projected impacts of the Final Rule can then be determined against this backdrop.

In addition to the Final Rule and the no-action alternative, several alternative approaches were considered and ultimately rejected. The alternative of analyzing mandatory RTOs, as compared with voluntary RTOs as set forth in the Final Rule, was rejected as moot, since the EA assumes that voluntary RTO formation proceeds with little delay and is successful in creating RTOs with the functions and characteristics contained in the Rule. Hence, assumptions for voluntary RTOs and mandatory RTOs are analytically indistinguishable in terms of their effects on the transmission grid and on the electric sector generally.

The other major alternative considered was the analysis of alternative fuel price assumptions. Project for Sustainable FERC Energy Policy suggested that we prepare such an analysis. However, as we noted in the EA, this alternative was ultimately rejected for two reasons. First, as reflected in scenarios analyzed in the EIS for Order No. 888, plausible variation in gas prices relative to coal prices is unlikely to have a major impact on the environmental effects of the Final Rule. Therefore, a gas price scenario was selected that had the general characteristics of other forecasts, namely, that gas prices will rise relative to coal prices. The selection of this gas price scenario does not represent an endorsement of this particular gas price path. Although we believe it to be a reasonable projection, it is a merely a representative projection of gas prices for purposes of the EA. Second, there is no need to consider an alternative where competition favors gas over coal because such a scenario would have little adverse impact, especially when compared with scenarios that tend to favor increased coal use relative to gas use. In the rule scenario we selected, we included, therefore, a number of improvements in coal technology as a result of the RTO Rule, to ensure that the potential impacts of any increased coal use relative to the base case would be considered in assessing the environmental consequences of the rule.

E. Analytic Framework and Assumptions

It is expected that the impacts of the Final Rule will result primarily from changes in the types and locations of power plants and transmission facilities constructed in the future and changes in the operating patterns of existing power plants, including changes in the fuel mix. To examine the impacts thoroughly, the modeling approach chosen includes detailed representations of electric power plants and the electric transmission grid, and allows for an economic (least-cost) compliance with existing and future environmental regulatory requirements.

Computer modeling capable of simulating regional electric utility dispatch and capacity expansion over time was used to characterize electric power markets in the base case and rule scenarios. We used a large supply optimization model of the U.S. electricity supply sector, which emphasizes pollution estimation and pollution control. It has been used for Environmental Protection Agency (EPA) regulatory analysis in publicly accessible proceedings since 1996.

Analytic assumptions are a critical part of the modeling. Because the model cannot tell us directly what the RTO-related changes will be, it must assess how a set of assumed changes in the cost and/or physical properties or the electricity system could lead to changes in the use of the system, and hence to changes in emissions.

A series of specific assumptions were developed to model the base case and scenarios. Assumptions common to all modeled cases include current and future prices of fossil fuels, particularly coal and natural gas, and current and future requirements imposed on the electric sector by environmental laws and regulations. These requirements include: for SO_2, continuation of the Title IV Acid Rain Program, with Phase II coverage and levels of permitted emissions; for NO_X, Title IV requirements on coal-fired boilers (Phase I and Phase II); emissions cap restrictions in the Ozone Transport Region starting in 1999, and implementation of the Final Rule governing ozone transport issued by the EPA in 1997, modeled in accordance with the EPA's guidance. This EPA Rule imposes a cap on NO_X on large utility boilers in 22 states in the eastern United States and limiting summer NO_X emissions to 543,800 tons; no regulatory restrictions are assumed for mercury or CO_2.

Project Groups commented that, since assumptions made in the EA about future environmental regulations are critical in determining the outcome of the analysis, changes in future environmental regulations (particularly due to legal challenges) from those assumed in the EA could result in different environmental impacts. Accordingly, the comment states that the EA should reflect possible changes. We note that there are many important analytic assumptions embodied in the modeling for the EA. Environmental regulations are directly represented in the analysis, and changes in these assumed regulations do have a large effect on the results of the modeling. In particular, the presence or absence of SO_2 and NO_X caps is a key assumption. Nevertheless, these assumptions are based on regulations which are final, as opposed to proposed regulations or speculative regulatory actions. These rules and associated regulatory analyses from EPA were used as the basis for the EA assumptions. Accordingly, it would be premature and speculative to consider changes, if any, from pending legal challenges or speculative future regulatory changes.

In a broader sense, it is clear that successful competitive energy markets will be complemented by cost-effective environmental regulation, because the incentives for efficient behavior on the part of market participants can be decentralized and the need for intrusive regulatory action is lessened. Emissions trading programs such as those for SO_2 and NO_X are an important example of such cost-effective regulation.

Other invariant assumptions include: net electric demand growth (with the exception of New Entry Scenario); load shape (how demand varies with season and time of day within each model region); costs and performance of new power plants; and capacity and generation of nuclear, hydroelectric, pumped storage, and import supply.

Because of the importance of the transmission system in the Rule, assumptions were made about potential changes that may come about either because of the Rule's requirements or because of its increased incentives for better grid operation and investment. In addition, the Final Rule is expected to develop more competitive bulk electric power markets. Competition is expected to increase the incentives for efficient behavior among market participants. To assess the potential effects of such increased efficiencies on the environment, some assumptions affecting new and existing power plants were changed. Finally, to respond to concerns expressed by parties in the scoping process regarding the role of new entrants in developing competitive power markets, particularly the RTOs, a model scenario was developed that specifically addresses new entry and enhanced consumer choice.

F. Impacts

The EA analyzes the electric power capacity and generation projections on a national and regional level for the base case, and presents the corresponding environmental impacts. Projected trends in generating capacity, including economic additions, retirements and modifications, and generation by plant type for the base case, are analyzed for the years 2005, 2010, and 2015. The data indicate that virtually all future capacity additions are expected to be gas-fired combined cycle or combustion turbine units; coal will nevertheless remain the dominant fuel for generation. Growth in natural gas, however, will be rapid, with the share of generation increasing from 13 percent in 1997 to 32 percent in 2015; total generating capacity is expected to grow at a slower rate than demand, resulting in plants that will generally be operated at higher capacity factors; regional patterns of generation reflect regional demand growth as well as changes in interregional trade in electricity. In most regions, growth in demand is met by gas-fired (or oil/gas switching) plants, although in the Midwest existing coal-fired capacity meets part of the growth in the early years of the forecast.

The EA projects national emissions in the base case for SO_2, NO_X, mercury, and CO_2. There are also regional emissions projections for NO_X. The analysis indicates the following:

1. SO_2 emissions will decline gradually to 9.5 million tons in 2015. Variations in such emissions during the forecast period primarily reflect economic use of the Title IV emissions banking program, under which emitting parties may elect to over-control SO_2 in any year and bank the extra reductions as emission credits for later use;

2. Regional SO_2 emissions generally will follow the same pattern as the national emissions total. However, emissions reductions and shifts are not expected to occur uniformly across regions because the SO_2 emissions trading program allows emitting parties with higher costs of pollution control to purchase allowances from emitting parties with lower control costs. This can lead to increases in emissions from certain regions;

3. NO_X emissions are projected to decline to 4.1 million tons in 2015. These reductions are due to the development of NO_X regulations under the Clean Air Act. Furthermore, summer or ''ozone season'' (May to September) NO_X emissions are projected to decrease to 1.3 million tons in 2015;

4. Regional NO_X emissions are projected to follow a pattern similar to the national trend; however, the implementation of NO_X controls is assumed to take the form of an emission cap and permit trading program similar to the Title IV SO_2 program. Consequently, certain regions may experience different NO_X emissions trends because of the relative costs of controlling NO_X and the possibility of trading between emitting parties;

5. CO_2 is projected to increase throughout the analysis period by 27 percent. Because CO_2 is an unregulated pollutant at the present time, and because both coal and natural gas emit CO_2, the rise in both coal and gas-fired generation leads to a substantial increase in CO_2 emissions during the analysis period; and

6. Mercury emissions range between 50.6 and 53.2 tons during the forecast period with no clear trend distinguishable. Mercury is also uncontrolled at the present time, but emissions are closely linked to coal use (with considerable variation of mercury content in coal from specific seams). The relative stability of coal-fired generation in later years of the analysis period leads to the observed pattern of mercury emissions.

The analysis indicates that the Midwest is expected to produce slightly more power, the East Coast to produce slightly less power. These changes are likely to be greatest in the near-term, and to decline toward baseline levels over time. The Final Rule would result in the slight shifting of the baseline fuel mix projections toward coal and away from fuel oil and, to some extent, natural gas; these changes are small relative to the overall trend in the fuel mix, in which natural gas remains the most rapidly growing fuel. This is consistent with the change in regional levels of generation.

The analysis shows that the overall emissions of SO_X, NO_X, mercury, and CO_2, are directionally consistent with the observed changes in power generation and fuel mix. That is, emissions tend to increase early in the forecast period and then decline over time, with several instances of emissions reductions. The greatest change in any regulated pollutant (a rise of 3.6 percent or 381,000 tons of SO_2 in one scenario) occurs as a result of changing patterns of emissions banking and trading, which is consistent with the design of the SO_2 cap and trade regulatory program. Regional variations in annual and summer NO_X are also possible and are also consistent with regulatory program design. Emissions budgets are met at all times. Other emission changes are relatively small because coal-fired plants, which contribute a disproportionate share of these emissions, are already heavily utilized and so are unable to increase their output significantly in the rulemaking scenarios. In one scenario designed to examine increased new entry and demand flexibility, substantial emissions reductions occur as a result of lower demand for electricity combined with cleaner new supply options.

V. Regulatory Flexibility Act Certification

The Commission received no comments on its certification, in the NOPR, that the proposed rule would not have a significant economic impact on a substantial number of small entities and that an initial regulatory flexibility analysis is not required by 5 U.S.C. § 603. The Commission adheres to its earlier reasoning and thus concludes that a final regulatory flexibility analysis also is not required.[753] In making this determination, the Commission is required to examine only the direct compliance costs that a rulemaking imposes upon small businesses. It is not required to consider indirect economic consequences, nor is it required to consider costs that an entity incurs voluntarily.[754] This rulemaking does not impose significant compliance costs upon small entities. Instead, it leaves them with the choice of whether to join an RTO. The only costs that are mandated are the minimal costs associated with filing a statement, in the event a public utility does not make an RTO filing, explaining its efforts to join an RTO, any barriers it encountered, and any future plans to join an RTO. Thus, this rulemaking will not have a significant economic impact upon any small entities.

VI. Public Reporting Burden and Information Collection Statement

The OMB regulations require OMB to approve certain reporting and recordkeeping (collections of information) imposed by agency rule.[755] The NOPR was submitted to OMB at the time of issuance. OMB did not comment nor did it take any action on the proposed rule. FERC identifies the information provided under Part 35 as FERC–516 [756] and under Part 33 as FERC–519.[757]

No comments from the public on the burden estimate were received. The filing requirements remain essentially the same as those in the NOPR so, therefore, the estimated annual filing burden remains the same. The burden estimates for complying with this proposed rule are set out in Table 1. The total annual hours for collection (reporting + recordkeeping (if appropriate)) is 7,600.

Information Collection Costs: The Commission has projected the average annualized cost for all respondents to be: Annualized Costs (Operations & Maintenance): $401,518 (7,600 hours ÷ 2080 hours per year × $109,889=$401,518). The cost per respondent is $7,722 (participants and non-participants).

TABLE 1.—ESTIMATED ANNUAL BURDEN

Data Collection	Number of Respondents	Number of Responses	Hours Per Response	Total Annual Hours
FERC–516 [1]	12	1	300	3,600
FERC–516 [2]	40	1	40	1,600
FERC–519 [1]	12	1	200	2,400
Totals				7,600

[1] Filings to propose participation in an RTO under § 35.34(d).
[2] Alternative filings under § 35.34(g).

Comments were solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

Title: FERC–516, Electric Rate Schedule Filings; FERC–519 Application for Sale, Lease, or Other Disposition, Merger or Consolidation of Facilities or for the Purchase or Acquisition of Securities of a Public Utility.

Action: Proposed Data Collections.

OMB Control No.: 1902–0096 and 1902–0082.

The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit, including small businesses.

Frequency of Responses: One time.

Necessity of Information: The Final Rule revises the requirements contained in 18 CFR part 35. The Commission is promoting the voluntary establishment of RTOs nationwide by December 2001. In particular, the Commission will establish in this rule characteristics and functions which applicants must meet to become Commission-approved RTOs. The Commission will engage in a collaborative process with state officials and others to facilitate RTO development. The rule will require that each public utility that owns, operates or controls transmission facilities participate in one-time filings proposing an RTO or make a filing explaining why they are not participating in an RTO proposal.

Internal Review: The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. The Commission's Office of Markets, Tariffs and Rates will use the data included in filings under 18 CFR 35.34 to evaluate efforts for the interconnection and coordination of the U.S. electric transmission system and to ensure the orderly formation of RTOs as well as for general industry oversight. These information requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric power industry.

The Commission received approximately 334 comments and reply comments on its NOPR but none on its reporting burden. The Commission's responses to the comments are addressed in the preamble of this Final

[753] *See* 5 U.S.C. 604.

[754] *Mid-Tex Elec. Coop.* v. *FERC,* 773 F.2d 327 (D.C. Cir. 1985) (Commission need only consider small entities ''that would be directly regulated''); *Colorado State Banking Bd.* v. *RTC,* 926 F.2d 931 (10th Cir. 1991) (Regulatory Flexibility Act not implicated where regulation simply added an option for affected entities and did not impose any costs).

[755] 5 CFR 1320.11, 44 U.S.C. 3507(d).

[756] Electric Rate Schedule Filings.

[757] Application for Sale, Lease, or Other Disposition, Merger or Consolidation of Facilities or for the Purchase or Acquisition of Securities of a Public Utility.

Rule. The Commission is submitting a copy of the Final Rule along with information collection submissions for the data collections identified above to OMB for its review and approval.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Michael Miller, Office of the Chief Information Officer, Phone: (202) 208–1415, fax: (202) 208–2425, E-mail: *mike.miller@ferc.fed.us*] or send your comments to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503, [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–3087, fax: (202) 395–7285].

VII. Effective Date and Congressional Notification

This rule will take effect March 6, 2000. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this Rule is a ''major rule'' within the meaning of section 351 of the Small Business Regulatory Enforcement Act of 1996.[758] The Rule will be submitted to both Houses of Congress and the Comptroller General prior to its publication in the **Federal Register**.

VIII. Document Availability

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.fed.us*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

From FERC's Home Page on the Internet, this information is available in both the Commission Issuance Posting System (CIPS) and the Records and Information Management System (RIMS).

- CIPS provides access to the texts of formal documents issued by the Commission since November 14, 1994. CIPS can be accessed using the CIPS link or the Energy Information Online icon. The full text of this document will be available on CIPS in ASCII and WordPerfect 8.0 format for viewing, printing, and/or downloading.
- RIMS contains images of documents submitted to and issues by the Commission after November 16, 1981. Documents from November 1995 to the present can be viewed and printed from FERC's Home Page using the RIMS link or the Energy Information Online icon. Descriptions of documents back to November 16, 1981, are also available from RIMS-on-the-Web; requests for copies of these and other older documents should be submitted to the Public Reference Room.

User assistance is available for RIMS, CIPS, and the Website during normal business hours from our Help line at (202) 208–2222 (e-mail to WebMaster@ferc.fed.us) of the Public Reference Room at (202) 208–1371 (e-mail to *public.referenceroom@ferc.fed.us*).

During normal business hours, documents can also be viewed and/or printed in FERC's Public Reference Room, where RIMS, CIPS, and the FERC Website are available. User assistance is also available.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements

By the Commission.

David P. Boergers,

Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18 of the *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by adding a new Subpart F and a new § 35.34 to read as follows:

Subpart F—Procedures and Requirements Regarding Regional Transmission Organizations

§ 35.34 Regional Transmission Organizations.

(a) *Purpose.* This section establishes required characteristics and functions for Regional Transmission Organizations for the purpose of promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services. This section further directs each public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce to make certain filings with respect to forming and participating in a Regional Transmission Organization.

(b) *Definitions.*

(1) *Regional Transmission Organization* means an entity that satisfies the minimum characteristics set forth in paragraph (j) of this section, performs the functions set forth in paragraph (k) of this section, and accommodates the open architecture condition set forth in paragraph (l) of this section.

(2) *Market participant* means:

(i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides transmission or ancillary services to the Regional Transmission Organization, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions; and

(ii) Any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions.

(3) *Affiliate* means the definition given in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11)).

(4) *Class of market participants* means two or more market participants with common economic or commercial interests.

(c) *General rule.* Except for those public utilities subject to the requirements of paragraph (h) of this section, every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000 must file with the Commission, no later than October 15, 2000, one of the following:

(1) A proposal to participate in a Regional Transmission Organization consisting of one of the types of submittals set forth in paragraph (d) of this section; or

(2) An alternative filing consistent with paragraph (g) of this section.

(d) *Proposal to participate in a Regional Transmission Organization.* For purposes of this section, a proposal to participate in a Regional Transmission Organization means:

(1) Such filings, made individually or jointly with other entities, pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as are necessary to create a new Regional Transmission Organization;

[758] 5 U.S.C. 804(2).

(2) Such filings, made individually or jointly with other entities, pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as are necessary to join a Regional Transmission Organization approved by the Commission on or before the date of the filing; or

(3) A petition for declaratory order, filed individually or jointly with other entities, asking whether a proposed transmission entity would qualify as a Regional Transmission Organization and containing at least the following:

(i) A detailed description of the proposed transmission entity, including a description of the organizational and operational structure and the intended participants;

(ii) A discussion of how the transmission entity would satisfy each of the characteristics and functions of a Regional Transmission Organization specified in paragraphs (j), (k) and (l) of this section;

(iii) A detailed description of the Federal Power Act section 205 rates that will be filed for the Regional Transmission Organization; and

(iv) A commitment to make filings pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as necessary, promptly after the Commission issues an order in response to the petition.

(4) Any proposal filed under this paragraph (d) must include an explanation of efforts made to include public power entities in the proposed Regional Transmission Organization.

(e) *Innovative transmission rate treatments for Regional Transmission Organizations.*

(1) The Commission will consider authorizing any innovative transmission rate treatment, as discussed in this paragraph (e), for an approved Regional Transmission Organization. An applicant's request must include:

(i) A detailed explanation of how any proposed rate treatment would help achieve the goals of Regional Transmission Organizations, including efficient use of and investment in the transmission system and reliability benefits to consumers;

(ii) A cost-benefit analysis, including rate impacts; and

(iii) A detailed explanation of why the proposed rate treatment is appropriate for the Regional Transmission Organization.

The applicant must support any rate proposal under this paragraph (e) as just, reasonable, and not unduly discriminatory or preferential.

(2) For purposes of this paragraph (e), innovative transmission rate treatment means any of the following:

(i) A transmission rate moratorium, which may include proposals based on formerly bundled retail transmission rates;

(ii) Rates of return that:

(A) Are formulary;

(B) Consider risk premiums and account for demonstrated adjustments in risk; or

(C) Do not vary with capital structure;

(iii) Non-traditional depreciation schedules for new transmission investment;

(iv) Transmission rates based on levelized recovery of capital costs;

(v) Transmission rates that combine elements of incremental cost pricing for new transmission facilities with an embedded-cost access fee for existing transmission facilities; or

(vi) Performance-based transmission rates.

(3) A request for performance-based transmission rates under this paragraph (e) may include factors such as:

(i) A method for calculating initial transmission rates (including price caps and any provisions for discounting);

(ii) A mechanism for adjusting initial rates, which may be derived from or based upon external factors or indices or a specific performance measure;

(iii) Time periods for redetermining initial rates; and

(iv) Costs to be excluded from performance-based rates.

(4) An innovative transmission rate treatment or any other rate proposal made for an approved Regional Transmission Organization may be requested as part of any filing that is made under paragraph (d) of this section or in any subsequent rate change proposal under section 205 of the Federal Power Act (16 U.S.C. 824d). Unless otherwise ordered by the Commission, an approved Regional Transmission Organization may not include in rates any innovative transmission rate treatment under paragraphs (e)(2)(i) and (e)(2)(ii)(C) of this section after January 1, 2005.

(f) *Transfer of operational control.* The public utility's proposal to participate in a Regional Transmission Organization filed pursuant to paragraph (c)(1) of this section must propose that operational control of that public utility's transmission facilities will be transferred to the Regional Transmission Organization on a schedule that will allow the Regional Transmission Organization to commence operating the facilities no later than December 15, 2001.

Note to paragraph (f): The requirement in paragraph (f) of this section may be satisfied by proposing to transfer to the Regional Transmission Organization ownership of the facilities in addition to operational control.

(g) *Alternative filing.* Any filing made pursuant to paragraph (c)(2) of this section must contain:

(1) A description of any efforts made by that public utility to participate in a Regional Transmission Organization;

(2) A detailed explanation of the economic, operational, commercial, regulatory, or other reasons the public utility has not made a filing to participate in a Regional Transmission Organization, including identification of any existing obstacles to participation in a Regional Transmission Organization; and

(3) The specific plans, if any, the public utility has for further work toward participation in a Regional Transmission Organization, a proposed timetable for such activity, an explanation of efforts made to include public power entities in the proposed Regional Transmission Organization, and any factors (including any law, rule or regulation) that may affect the public utility's ability or decision to participate in a Regional Transmission Organization.

(h) *Public utilities participating in approved transmission entities.* Every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000, and that has filed with the Commission on or before March 6, 2000 to transfer operational control of its facilities to a transmission entity that has been approved or conditionally approved by the Commission on or before March 6, 2000 as being in conformance with the eleven ISO principles set forth in Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶ 31,036 (Final Rule on Open Access and Stranded Costs), must, individually or jointly with other entities, file with the Commission, no later than January 15, 2001:

(1) A statement that it is participating in a transmission entity that has been so approved;

(2) A detailed explanation of the extent to which the transmission entity in which it participates has the characteristics and performs the functions of a Regional Transmission Organization specified in paragraphs (j) and (k) of this section and accommodates the open architecture conditions in paragraph (l) of this section; and

(3) To the extent the transmission entity in which the public utility participates does not meet all the requirements of a Regional Transmission Organization specified in paragraphs (j), (k), and (l) of this section,

(i) A proposal to participate in a Regional Transmission Organization that meets such requirements in accordance with paragraph (d) of this section,

(ii) A proposal to modify the existing transmission entity so that it conforms to the requirements of a Regional Transmission Organization, or

(iii) A filing containing the information specified in paragraph (g) of this section addressing any efforts, obstacles, and plans with respect to conformance with those requirements.

(i) *Entities that become public utilities with transmission facilities.* An entity that is not a public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000, but later becomes such a public utility, must file a proposal to participate in a Regional Transmission Organization in accordance with paragraph (d) of this section, or an alternative filing in accordance with paragraph (g) of this section, by October 15, 2000 or 60 days prior to the date on which the public utility engages in any transmission of electric energy in interstate commerce, whichever comes later. If a proposal to participate in accordance with paragraph (d) of this section is filed, it must propose that operational control of the applicant's transmission system will be transferred to the Regional Transmission Organization within six months of filing the proposal.

(j) *Required characteristics for a Regional Transmission Organization.* A Regional Transmission Organization must satisfy the following characteristics when it commences operation:

(1) *Independence.* The Regional Transmission Organization must be independent of any market participant. The Regional Transmission Organization must include, as part of its demonstration of independence, a demonstration that it meets the following:

(i) The Regional Transmission Organization, its employees, and any non-stakeholder directors must not have financial interests in any market participant.

(ii) The Regional Transmission Organization must have a decision making process that is independent of control by any market participant or class of participants.

(iii) The Regional Transmission Organization must have exclusive and independent authority under section 205 of the Federal Power Act (16 U.S.C. 824d), to propose rates, terms and conditions of transmission service provided over the facilities it operates.

Note to paragraph (j)(1)(iii): Transmission owners retain authority under section 205 of the Federal Power Act (16 U.S.C. 824d) to seek recovery from the Regional Transmission Organization of the revenue requirements associated with the transmission facilities that they own.

(2) *Scope and regional configuration.* The Regional Transmission Organization must serve an appropriate region. The region must be of sufficient scope and configuration to permit the Regional Transmission Organization to maintain reliability, effectively perform its required functions, and support efficient and non-discriminatory power markets.

(3) *Operational authority.* The Regional Transmission Organization must have operational authority for all transmission facilities under its control. The Regional Transmission Organization must include, as part of its demonstration of operational authority, a demonstration that it meets the following:

(i) If any operational functions are delegated to, or shared with, entities other than the Regional Transmission Organization, the Regional Transmission Organization must ensure that this sharing of operational authority will not adversely affect reliability or provide any market participant with an unfair competitive advantage. Within two years after initial operation as a Regional Transmission Organization, the Regional Transmission Organization must prepare a public report that assesses whether any division of operational authority hinders the Regional Transmission Organization in providing reliable, non-discriminatory and efficiently priced transmission service.

(ii) The Regional Transmission Organization must be the security coordinator for the facilities that it controls.

(4) *Short-term reliability.* The Regional Transmission Organization must have exclusive authority for maintaining the short-term reliability of the grid that it operates. The Regional Transmission Organization must include, as part of its demonstration with respect to reliability, a demonstration that it meets the following:

(i) The Regional Transmission Organization must have exclusive authority for receiving, confirming and implementing all interchange schedules.

(ii) The Regional Transmission Organization must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities.

(iii) When the Regional Transmission Organization operates transmission facilities owned by other entities, the Regional Transmission Organization must have authority to approve or disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards.

(iv) If the Regional Transmission Organization operates under reliability standards established by another entity (*e.g.,* a regional reliability council), the Regional Transmission Organization must report to the Commission if these standards hinder it from providing reliable, non-discriminatory and efficiently priced transmission service.

(k) *Required functions of a Regional Transmission Organization.* The Regional Transmission Organization must perform the following functions. Unless otherwise noted, the Regional Transmission Organization must satisfy these obligations when it commences operations.

(1) *Tariff administration and design.* The Regional Transmission Organization must administer its own transmission tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities. As part of its demonstration with respect to tariff administration and design, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(1) (i) and (ii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own Commission-approved open access transmission tariff. The Regional Transmission Organization must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The Regional Transmission Organization must have the authority to review and approve requests for new interconnections.

(ii) Customers under the Regional Transmission Organization tariff must not be charged multiple access fees for the recovery of capital costs for transmission service over facilities that the Regional Transmission Organization controls.

(2) *Congestion management.* The Regional Transmission Organization must ensure the development and operation of market mechanisms to

manage transmission congestion. As part of its demonstration with respect to congestion management, the Regional Transmission Organization must satisfy the standards listed in paragraph (k)(2)(i) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions. The Regional Transmission Organization must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant.

(ii) The Regional Transmission Organization must satisfy the market mechanism requirement no later than one year after it commences initial operation. However, it must have in place at the time of initial operation an effective protocol for managing congestion.

(3) *Parallel path flow.* The Regional Transmission Organization must develop and implement procedures to address parallel path flow issues within its region and with other regions. The Regional Transmission Organization must satisfy this requirement with respect to coordination with other regions no later than three years after it commences initial operation.

(4) *Ancillary services.* The Regional Transmission Organization must serve as a provider of last resort of all ancillary services required by Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶ 31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders. As part of its demonstration with respect to ancillary services, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(4)(i)–(iii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) All market participants must have the option of self-supplying or acquiring ancillary services from third parties subject to any restrictions imposed by the Commission in Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶ 31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders.

(ii) The Regional Transmission Organization must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All ancillary service providers must be subject to direct or indirect operational control by the Regional Transmission Organization. The Regional Transmission Organization must promote the development of competitive markets for ancillary services whenever feasible.

(iii) The Regional Transmission Organization must ensure that its transmission customers have access to a real-time balancing market. The Regional Transmission Organization must either develop and operate this market itself or ensure that this task is performed by another entity that is not affiliated with any market participant.

(5) *OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC).* The Regional Transmission Organization must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC.

(6) *Market monitoring.* To ensure that the Regional Transmission Organization provides reliable, efficient and not unduly discriminatory transmission service, the Regional Transmission Organization must provide for objective monitoring of markets it operates or administers to identify market design flaws, market power abuses and opportunities for efficiency improvements, and propose appropriate actions. As part of its demonstration with respect to market monitoring, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(6)(i) through (k)(6)(iii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) Market monitoring must include monitoring the behavior of market participants in the region, including transmission owners other than the Regional Transmission Organization, if any, to determine if their actions hinder the Regional Transmission Organization in providing reliable, efficient and not unduly discriminatory transmission service.

(ii) With respect to markets the Regional Transmission Organization operates or administers, there must be a periodic assessment of how behavior in markets operated by others (*e.g.,* bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects Regional Transmission Organization operations and how Regional Transmission Organization operations affect the efficiency of power markets operated by others.

(iii) Reports on opportunities for efficiency improvement, market power abuses and market design flaws must be filed with the Commission and affected regulatory authorities.

(7) *Planning and expansion.* The Regional Transmission Organization must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and coordinate such efforts with the appropriate state authorities. As part of its demonstration with respect to planning and expansion, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(7)(i) and (ii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization planning and expansion process must encourage market-driven operating and investment actions for preventing and relieving congestion.

(ii) The Regional Transmission Organization's planning and expansion process must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The Regional Transmission Organization's planning and expansion process must be coordinated with programs of existing Regional Transmission Groups (See § 2.21 of this chapter) where appropriate.

(iii) If the Regional Transmission Organization is unable to satisfy this requirement when it commences operation, it must file with the Commission a plan with specified milestones that will ensure that it meets this requirement no later than three years after initial operation.

(8) *Interregional coordination.* The Regional Transmission Organization must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

(l) *Open architecture.*

(1) Any proposal to participate in a Regional Transmission Organization must not contain any provision that would limit the capability of the Regional Transmission Organization to evolve in ways that would improve its efficiency, consistent with the requirements in paragraphs (j) and (k) of this section.

(2) Nothing in this regulation precludes an approved Regional Transmission Organization from seeking to evolve with respect to its organizational design, market design,

geographic scope, ownership arrangements, or methods of operational control, or in other appropriate ways if the change is consistent with the requirements of this section. Any future filing seeking approval of such changes must demonstrate that the proposed changes will meet the requirements of paragraphs (j), (k) and (l) of this section.

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix to Preamble—List of Commenters

Abbreviation—Commenter

1. Advisory Committee ISO–NE—Advisory Committee to the Board of Directors of ISO New England.
2. AEP—American Electric Power Service Corporation and its public utility operating company subsidiaries: Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company. and Wheeling Power Company.
3. AEPCO—Arizona Electric Power Cooperative, Inc.
4. Alabama Commission—Alabama Public Service Commission.
5. Alberta—Provence of Alberta, Electricity Branch.
6. Allegheny—Allegheny Energy, Inc.
7. Alliance Companies—American Electric Power Service Corporation, Consumers Energy Company, Detroit Edison Company, FirstEnergy Corp. and Virginia Electric and Power Company.
8. Alliant Energy—Alliant Energy Corporation.
9. Aluminum Companies—Alcoa Inc., Columbia Falls Aluminum Company, Kaiser Aluminum & Chemical Corporation and Vanalco, Inc.
10. American Forest—American Forest & Paper Association.
11. AMP-Ohio—American Municipal Power-Ohio, Inc.
12. APPA—American Public Power Association.
13. APPA *et al.* (WP)—Legal White Paper prepared on behalf of and sponsored jointly by the American Public Power Association, the Electric Consumers Resource Council, the Transmission Access Policy Study Group and the Transmission Dependent Utility Systems.
14. APS—Arizona Public Service Company.
15. APX—Automated Power Exchange, Inc.
16. Arizona Authority—Arizona Power Authority.
17. Arizona Commission—Arizona Corporation Commission.
18. Arizona ISA—Arizona Independent Scheduling Administrator Association.
19. Arkansas Cities—Cities of Benton, Bentonville, North Little Rock, Osceola, Piggott, Prescott and Siloam Springs, Arkansas; the Clarksville Light and Water Company; Conway Corporation; Hope Water and Light Commission; City Water and Light Plant of the City of Jonesboro, Arkansas; Paragould Light and Water Commission; and the West Memphis, Arkansas Utilities Commission.
20. Arkansas Consumers—Arkansas Electric Energy Consumers.
21. Avista—Avista Corporation, Inc.
22. Bangor Hydro—Bangor Hydro-Electric Company.
23. BC Hydro—British Columbia Hydro & Power Authority.
24. Big Rivers—Big Rivers Electric Corporation.
25. Blue Ridge—Blue Ridge Power Agency.
26. Brattle Group—The Brattle Group (Peter Fox-Penner and Philip Hanser).
27. British Columbia Ministry—British Columbia, Canada, Ministry of Employment and Investment, Electricity Development Branch.
28. Cal DWR—California Department of Water Resources.
29. Cal ISO—California Independent System Operator Corporation.
30. California Board—California Electricity Oversight Board.
31. California Commission—Public Utilities Commission of the State of California.
32. CalPX—California Power Exchange Corporation.
33. CAMU—Colorado Association of Municipal Utilities.
34. Canada DNR—Canada Department of Natural Resources.
35. CCEM/ELCON—Coalition for a Competitive Electricity Market and the Electricity Consumers Resources Council.
36. CEA—Canadian Electricity Association.
37. Consumers Energy—Consumers Energy Company.
38. Central Maine—Central Maine Power Company and Maine Electric Power Company.
39. Champion—Champion International Corporation.
40. Chelan—Public Utility District No. 1 of Chelan County.
41. Cinergy—Cinergy Services, Inc.
42. Clarksdale—Clarksdale Public Utilities Commission.
43. Cleco—Cleco Corporation.
44. Cleveland—City of Cleveland, Ohio.
45. CMUA—California Municipal Utilities Association.
46. Coalition of Alliance Users—Coalition of Municipal and Cooperative Users of Alliance Companies' Transmission.
47. ComEd—Commonwealth Edison Company.
48. Conectiv—Conectiv (Atlantic City Electric Company and Delmarva Power & Light Company.
49. Conlon—Mr. P. Gregory Conlon.
50. Consumer Groups—Industrial Consumers, American Public Power Association, National Rural Electric Cooperative Association, Transmission Access Policy Study Group, Transmission Dependent Utility Systems, Consumer Federation of America and International Mass Retail Association.
51. CP&L—Carolina Power & Light Company.
52. CRC—Colorado River Commission of the State of Nevada.
53. CREDA—Colorado River Energy Distributors Association.
54. CSU—Colorado Springs Utilities.
55. CTA—Competitive Transmission Association, Inc.
56. Dalton Utilities—Board of Water, Light and Sinking Fund Commissioners of the City of Dalton, Georgia.
57. Dairyland—Dairyland Power Cooperative.
58. Desert STAR—Desert STAR.
59. Detroit Edison—Detroit Edison Company.
60. Distributed Power—Distributed Power Coalition of America.
61. DOE—United States Department of Energy.
62. Dr. Illic—Dr. Marija Illic and Yong Yoon.
63. Duke—Duke Energy Corporation.
64. Duquesne—Duquesne Light Company.
65. Dynegy—Dynegy Inc.
66. EAL—ESBI Alberta Ltd.
67. East Kentucky—East Kentucky Power Cooperative, Inc.
68. East Texas Cooperatives—East Texas Electric Cooperative, Inc., Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc.
69. ECAR—East Central Area Reliability Council.
70. EEI—Edison Electric Institute.
71. EME—Edison Mission Energy.
72. Empire District—Empire District Electric Company.
73. Enron/APX/Coral Power—Enron Power Marketing, Inc., Automated Power Exchange and Coral Power, L.L.C.
74. Entergy—Entergy Services Inc.
75. EPA—United States Environmental Protection Agency.
76. EPRI—Electric Power Research Institute.
77. EPSA—Electric Power Supply Association.
78. Eric Hirst—Mr. Eric Hirst.
79. Fertilizer Institute—The Fertilizer Institute.
80. First Rochdale—1st Rochdale Cooperative Group, Ltd.
81. FirstEnergy—FirstEnergy Corp.
82. Florida Commission—Florida Public Service Commission.
83. Florida Power Corp.—Florida Power Corporation.
84. FMPA—Florida Municipal Power Agency.
85. FP&L—Florida Power & Light Company.
86. FTC—Staff of the Bureau of Economics of the Federal Trade Commission.
87. Gainesville—Gainesville Regional Utilities.
88. Georgia Transmission—Georgia Transmission Corporation.
89. GPU Energy—GPU Energy.
90. Grand Council et al.—Grand Council of the Crees, Greenpeace Canada, the Sierra Club of Canada, Mouvement Au Courant, the Centre D'Analyses de Politiques Energetiques and New England Coalition for Energy Efficiency and the Environment.
91. Great River—Great River Energy.
92. H.Q. Energy Services—Energy Services Group of Hydro-Quebec and H.Q. Energy Services (U.S.) Inc.
93. How Group—OASIS How Working Group.
94. ICUA—Idaho Consumer-Owned Utilities Association.

95. Idaho Commission—Idaho Public Utilities Commission.
96. Idaho Power—Idaho Power Company.
97. Illinois Commission—Illinois Commerce Commission.
98. IMEA—Illinois Municipal Electric Agency.
99. IMPA—Indiana Municipal Power Agency.
100. Indiana Commission—Indiana Utility Regulatory Commission.
101. Indianapolis P&L—Indianapolis Power & Light Company.
102. Industrial Consumers—Electricity Consumers Resource Council, the American Iron & Steel Institute and the Chemical Manufactures Association.
103. Industrial Customers—Industrial Customers of Northwest Utilities.
104. INGAA—Interstate Natural Gas Association of America.
105. Iowa Board—Iowa Utilities Board.
106. IPCF—International Powerline Communications Forum.
107. ISO–NE—ISO New England Inc.
108. JEA—JEA.
109. Justice Department—United States Department of Justice.
110. Kentucky Commission—Kentucky Public Service Commission.
111. Konolige/Ford/Fleishman—Kit Konolige, Daniel F. Ford and Steven I. Fleishman.
112. Lenard—Mr. Thomas M. Lenard.
113. LEPA—Louisiana Energy & Power Authority.
114. LG&E—LG&E Energy Corp.
115. Lincoln—Lincoln, Nebraska Electric System.
116. LIPA—Long Island Power Authority.
117. Los Angeles—Los Angeles Department of Water and Power.
118. Loveland Customers—Loveland Area Customers Association.
119. LPPC—Large Public Power Council.
120. Manitoba Board—Manitoba Hydro-Electric Board.
121. MAPP—Mid-Continent Area Power Pool.
122. Mass Companies—Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company.
123. Massachusetts Division—Massachusetts Division of Energy Resources.
124. MEAG—Municipal Electric Authority of Georgia.
125. Merrill Energy—Merrill Energy LLC.
126. Metropolitan—Metropolitan Water District of Southern California.
127. Michigan Commission—Michigan Public Service Commission.
128. MidAmerican—MidAmerican Energy Company.
129. Mid-Atlantic Commissions—Delaware Public Service Commission, District of Columbia Public Service Commission, Maryland Public Service Commission, New Jersey Board of Public Utilities and Pennsylvania Public Utility Commission.
130. Midwest Energy—Midwest Energy, Inc.
131. Midwest ISO—Midwest Independent Transmission System Operator, Inc.
132. Midwest ISO Participants—Allegheny Energy, Ameren, Central Illinois Light Company, Cinergy Corp., Commonwealth Edison Company, Hoosier Energy Rural Electric Cooperative, Inc., Illinois Power Company, Kentucky Utilities Company, Louisville Gas & Electric Company, Southern Indiana Gas & Electric Company, Southern Illinois Power Cooperative, Wabash Valley Power Association, Inc. and Wisconsin Electric Power Company.
133. Midwest Municipals—Missouri River Energy Services, Iowa Association of Municipal Utilities and Minnesota Municipal Utilities Association.
134. Minnesota Commission—Minnesota Public Utilities Commission.
135. Minnesota Power—Minnesota Power.
136. Missouri Commission—Missouri Public Service Commission.
137. MLGW—Memphis Light, Gas and Water Division.
138. Montana Commission—Montana Public Service Commission and Montana Department of Environmental Quality.
139. Montana Power—Montana Power Company.
140. Montana-Dakota—Montana-Dakota Utilities Co.
141. NARUC—National Association of Regulatory Utility Commissioners.
142. NASUCA—National Association of State Utility Consumer Advocates.
143. NCPA—Northern California Power Agency.
144. NEMA—National Energy Marketers Association.
145. NECPUC—New England Conference of Public Utilities Commissioners, Inc.
146. NEPCO et al.—New England Power Company, National Grid Group, plc and Montaup Electric Company.
147. NERA—National Economic Research Associates, Inc.
148. NERC—North American Electric Reliability Council.
149. Nevada Commission—Public Utilities Commission of Nevada
150. New Century—New Century Energies, Inc. and its operating utility companies: Public Service Company of Colorado, Southwestern Public Service Company and Cheyenne Light, Fuel and Power Company.
151. New Orleans—Council of the City of New Orleans.
152. New Smyrna Beach—Utilities Commission, City of New Smyrna Beach, Florida.
153. New York Commission—New York State Public Service Commission
154. Nine Commissions—Pennsylvania Public Utility Commission, Virginia State Corporation Commission, Public Utilities Commission of Ohio, Indiana Utility Regulatory Commission, Illinois Commerce Commission, Michigan Public Service Commission, Missouri Public Service Commission, Arkansas Public Service Commission and Oklahoma Corporation Commission.
155. NiSource—NiSource Incorporated.
156. NJBUS—New Jersey Business Users.
157. NMA/WFA/CEED—National Mining Association, Western Fuels Association, Inc. and Center for Energy and Economic Development.
158. NU—Northeast Utilities System.
159. Northwest Council—Northwest Power Planning Council.
160. NPCC—Northeast Power Coordinating Council.
161. NPPD—Nebraska Public Power District.
162. NPRB—Nebraska Power Review Board.
163. NRECA—National Rural Electric Cooperative Association.
164. NSP—Northern States Power Company.
165. NU—Northeast Utilities System.
166. NWCC—National Wind Coordinating Committee.
167. NY ISO—New York Independent System Operator, Inc.
168. NYC—City of New York.
169. NYEBF—New York Energy Buyers Forum.
170. NYMEX—New York Mercantile Exchange.
171. NYPP—Member Systems of the New York Power Pool (Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corp. and Power Authority of the State of New York).
172. Oglethorpe—Oglethorpe Power Corporation.
173. Ohio Commission—Public Utilities Commission of Ohio.
174. Oneok—Oneok Power Marketing.
175. Ontario IMO—Ontario Independent Electricity Market Operator.
176. Ontario Power—Ontario Power Generation Inc.
177. Oregon Office—Oregon Office of Energy.
178. Otter Tail—Otter Tail Power Company.
179. PacifiCorp—PacifiCorp.
180. PECO—PECO Energy Company and Horizon Energy.
181. Pennsylvania Commission—Pennsylvania Public Utility Commission.
182. PG&E—PG&E Corporation.
183. PGE—Portland General Electric Company.
184. PGP—Public Generating Pool.
185. PJM—PJM Interconnection, L.L.C.
186. PJM/NEPOOL Customers—PJM Industrial Customer Coalition, NEPOOL Industrial Customer Coalition and Coalition of Midwest Transmission Customers.
187. Platte River—Platte River Power Authority.
188. PNGC—Pacific Northwest Generating Cooperative.
189. Powerex—British Columbia Power Exchange Corporation.
190. PP&L Companies—PP&L Inc., PP&L EnergyPlus Co., L.L.C., PP&L Montana, L.L.C.
191. PPC—Public Power Council.
192. Professor Hogan—Professor William W. Hogan.
193. Professor Joskow—Professor Paul L. Joskow.
194. Professor Koch—Professor Charles H. Koch, Jr.
195. Project Groups—Alliance for Affordable Energy, American Wind Energy Association, Center for Clean Air Policy, Center for Energy Efficiency and Renewable Technologies, Citizen Power, Inc., Citizens

for Pennsylvania's Future, Delaware Division of the Public Advocate, Environmental Law & Policy Center of the Midwest, Land & Water Fund of the Rockies, Legal Environmental Assistance Foundation, Minnesotans for an Energy-Efficient Economy, Natural Resources Defense Council, Northwest Energy Coalition, Office of the People's Counsel of the District of Columbia, Pace Energy Project, Pennsylvania Energy Project, Public Citizen, PJM Public Interest/Environmental User Group, Renew Wisconsin, Southern Environmental Law Center, Tennessee Valley Energy Reform Coalition, Union of Concerned Scientists, Wisconsin's Environmental Decade.

196. PSE&G—Public Service Electric and Gas Company.

197. PSNM—Public Service Company of New Mexico.

198. Public Citizen—Public Citizen.

199. Puget—Puget Sound Energy, Inc.

200. Rayburn—Rayburn Country Electric Cooperative, Inc.

201. RECA—Residential Electric Consumers Association.

202. Reliant—Reliant Energy, Incorporated.

203. RUS—Rural Utilities Service of the Department of Agriculture.

204. Salomon Smith Barney—Global Power Group of Salomon Smith Barney.

205. San Francisco—City and County of San Francisco.

206. SCE&G—South Carolina Electric & Gas Company.

207. Seattle—Seattle City Light Department.

208. SERC—Southeastern Electric Reliability Council.

209. Sierra Pacific—Sierra Pacific Resources, Inc.

210. Sithe—Sithe Energies, Inc.

211. SMUD—Sacramento Municipal Utility District.

212. Snohomish—Public Utility District No. 1 of Snohomish County, Washington.

213. SNWA—Southern Nevada Water Authority.

214. SoCal Cities—Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California.

215. SoCal Edison—Southern California Edison Company.

216. Sonat—Sonat Power Marketing, L.P.

217. South Carolina Authority—South Carolina Public Service Authority.

218. South Carolina Commission—Public Service Commission of South Carolina.

219. Southern Company—Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, GulfPower Company, Mississippi Power Company and Savannah Electric and Power Company.

220. SPP—Southwest Power Pool, Inc.

221. SPRA—Southwestern Power Resources Association.

222. SRP—Salt River Project Agricultural Improvement and Power District.

223. St. Joseph—St. Joseph Light & Power Company.

224. Statoil—Statoil Energy, Inc.

225. STDUG—Southwest Transmission Dependent Utility Group.

226. Steel Dynamics—Steel Dynamics, Inc.

227. Tacoma Power—City of Tacoma, Department of Public Utilities, Light Division.

228. Tallahassee—City of Tallahassee, Florida.

229. Tampa Electric—Tampa Electric Company.

230. TANC—Transmission Agency of Northern California.

231. TAPS—Transmission Access Policy Study Group.

232. TDU Systems—Alabama Electric Cooperative, Inc., Arkansas Electric Cooperative Corporation, Golden Spread Electric Cooperative, Kansas Electric Power Cooperative, Inc., North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, Seminole Electric Cooperative, Inc., and South Mississippi Electric Power Association.

233. Tennessee Authority—Tennessee Regulatory Authority.

234. TEP—Tucson Electric Power Company.

235. Texas Commission—Public Utility Commission of Texas.

236. Trans-Elect—Trans-Elect, Inc.

237. Transénergie—Transénergie.

238. Transmission ISO Participants—Baltimore Gas & Electric, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Energy Company, Conectiv, GPU Energy, Niagara Mohawk Power Company, Northeast Utilities Service Company, PECO Energy Company, PP&L, Inc., Potomac Electric Power Company, Public Service Electric and Gas Company, Vermont Electric Power Company, Inc.

239. Tri-State—Tri-State Generation and Transmission Association, Inc.

240. Turlock—Turlock Irrigation District.

241. TVA—Tennessee Valley Authority.

242. TXU Electric—TXU Electric Company.

243. UAMPS—Utah Associated Municipal Power Systems.

244. UMPA—Utah Municipal Power Agency.

245. United Illuminating—United Illuminating Company.

246. UtiliCorp—UtiliCorp United, Inc.

247. Utility Engineers—Utility Economic Engineers.

248. Vernon—City of Vernon, California.

249. Virginia Commission—Virginia State Corporation Commission.

250. Virginia Power—Virginia Electric and Power Company.

251. Washington Commission—Washington Utilities and Transportation Commission.

252. WEPCO—Wisconsin Electric Power Company.

253. WICF—Western Interconnection Coordination Forum.

254. Williams—Williams Companies, Inc.

255. Wisconsin Commission—Public Service Commission of Wisconsin.

256. Wolverine Cooperative—Wolverine Power Supply. Cooperative, Inc.

257. WPPI—Wisconsin Public Power, Inc.

258. WPSC—Wisconsin Public Service Corporation.

259. Wyoming Commission—Wyoming Public Service Commission.

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